POLITECNICO DI TORINO

Department of Environment, Land and Infrastructure Engineering

Master of Science in Petroleum Engineering

MASTER THESIS

OVERVIEW ON GAS CONDENSATE RESERVOIRS

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MARCH 2018

I ABSTRACT

The world will not run short of petroleum in the coming decades but it surely is at the verge of end to the easy-to-reach oil. This is due to the fact that most of the easily extractable near-surface hydrocarbons have been put into production. To cope with the increasing demand for hydrocarbons oil companies hence started to drill at higher depths both onshore and in deep waters to tap hard-to-extract oil reserves (MIT Technology Review, 2010). Higher depths with elevated conditions of temperature & pressure results in higher degree of degradation of complex organic molecules. So deeper burial of organic material leads to a higher tendency that organic material will be converted to gas or gas-condensate. Gas-condensate reservoirs are hence a potential asset of today and future. The importance also lies in fact that gas-condensate reservoirs are the source of gas as primary product and with some proportion of valuable heavy ends. Volume of gas market is increasing day by day as gas has become primary source for industries usage, power generation and other energy demands of the world.

But there are production problems associated with gas-condensate reservoirs. Due to production with time the bottom-hole pressure of producing well decreases, and when reaches below dew-point condensate accumulation starts around wellbore resulting in formation of condensate-bank. This condensate bank decreases gas-relative permeability and is the main source of productivity impairment and reduction of gas & condensate recoveries. So a precise understanding of the gas-condensate reservoir fluid-properties, phase- behavior, flow-behavior and the reservoir & well parameters like relative permeabilities of oil & gas, absolute permeability of reservoir, wettability preference of rock in the near well-bore region, completion type , optimum production rate etc. is imperative for optimum engineering of gas-condensate reservoirs and ultimately to improve the gas and condensate recoveries.

Many techniques are used to delay or to mitigate condensate-banking phenomena and to optimize the production from gas condensate reservoirs. These include hydraulic fracturing, drilling horizontal-wells and acidizing techniques to enhance productivity of well. Gas cycling, injection of N_2 & CO_2 are done to maintain reservoir-pressure above dew point and produce in the single gas phase. Similarly use of solvents & use of chemicals for wettability-alteration are done to reduce the adverse effects of condensate banking on production. A critical overview is provided of all these techniques using experimental work, case studies and field cases from the technical literature. Their Advantages, limitations and which technique is best to use in a given scenario are discussed.

II ACKNOWLEDGEMENTS

First of all I would like to express my sincere gratitude to my supervisor Prof. Vera Rocca for her continuous support, supervision and guidance throughout the research. I am very grateful to her for providing me valuable material which I found very useful in writing my thesis. I really appreciate her guidance and patience to answer my questions.

I would also like to thank to all my respected professors in Petroleum Department, without their knowledge and guidance it was not even possible to accomplish this research. I am grateful for their cooperation during the period of my thesis.

Last but not the least; I would like to give my heartfelt thanks to my family and friends. This study would have not been accomplished without their continued love, encouragement and appreciation.

III DEDICATION

This thesis is dedicated to my Parents.

For their endless love,

Support and encouragement.

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VI LIST OF ABBREVATIONS

ft – Foot

md – millidarci

PI – Productivity Index

PVT – Pressure Volume Temperature

CCE – Constant Composition Expansion

CVD – Constant Volume Depletion

CO2 – Carbon dioxide

N2 – Nitrogen

KH – Permeability × Thickness

Scf – Standard Cubic Foot

MM – Million

SM – Mechanical Skin

K – Permeability

IFT – Inter Facial Tensions

IPA – Iso-propyl Alcohol

GOR – Gas Oil Ratio

Swi – Irreducible water saturation

CGR – Condensate-gas ratio

1. INTRODUCTION

Petroleum-industry has developed into a highly advanced and technologically developed sector in the twenty first century, as most of the on shore and off shore shallow and accessible hydrocarbon reserves have been researched and thoroughly explored and hence put into production. This consequently means that new locations explorations are now targeted at even higher depths i.e. considerably tougher conditions of elevated-temperatures and higher pressures. Raised temperatures and high-pressure conditions surely result in higher tendency of the organic matter to be converted into gas condensates or gases. These factors arouse a loophole for extensive considerations of study and research in case of gas-condensate reservoirs as an exceptional potential asset for the current-scenario and for future perspective as well. Gas-condensate is not new resource but its importance is enormously increased in the current scenario due to the fact that gas-condensate reservoirs are more frequently encountered as now explorations are targeted at higher depths.

In retrospect, some very complex issues are linked with the nature of gas-condensate systems and they are even more advanced and challenging than the discrepancies in oil reservoirs. For example unlike conventional oil reservoirs, gas-condensate reservoirs are characterized by the phenomena of retrograde condensation which means gas-condensate reservoirs show complex compositional changes and phase behaviors when wells are produced below the dew point. Moreover as in oil reservoirs we can have near wellbore permeability damage phenomena called skin which reduces productivity, but in gas-condensate reservoirs we can have an addition near wellbore phenomena called condensate banking which severely reduces the well productivity. There are plentiful production concerns and exploitation problems which are should be properly addressed. Some vital variables including mobility effects, pore-size distribution, alteration in compositional contents, and interfacial-tensions are the factors that contribute in optimization and extraction of maximum yield from gas-condensate field. Since gas contracts are accorded at beginning of reservoir life span and for long span of time, so it becomes unavoidable and compulsory to provide the gas rate as per contractual requirements and avoid any production related problems. So precise analysis, achieving precise estimations and understanding of reservoir capabilities before starting production, schematization is a must for good management. In this thesis an in-depth critical analysis is carried out based on case studies from literature performed on all these issues and specific parameters which affect production from the gas-condensate reservoir are analyzed accordingly.

Gas condensate is basically a hydrocarbon mixture which mainly comprises of methane CH4 gas accompanied by other light-hydrocarbons and also a small portion of heavier constituents. Under certain temperature & pressure conditions, this condensate fluid will separate into a bi-phases mixture of gas and liquid commonly known as the retrograde condensate. Gas-condensate fluids are called retrograde due to their properties of reverse of pure components because when reservoir pressure propels below dew-point pressure, liquid droplets start condensing and as the pressure declines, liquid saturation increases as accordingly. But at a point as the system reaches a point in retrograde condensate whereas pressure declines further but then liquid re-vaporizes in an abnormal behavior.

The main issue linked with gas-condensate reservoirs is that during production as time passes so does the pressure at the bottom hole also declines until pressure falls to dew-point in area near to well bore region. This ultimately results in formation of liquid state hydrocarbons in the concerned region and in reservoir as well. As liquid hydrocarbon saturation in area near-well bore region rises, relative permeability of gas decreases, leading to substantial decrease in productivity of the well. This productivity issue which is typical of gas-condensate reservoirs is commonly termed as condensate banking or condensate ring or condensate-blockage and is a most obvious productivity issue of gas-condensate reservoirs having disastrous consequences resulting in marginal declining in productivity of the gas reservoirs. An example of a similar case of condensate dropout in vicinity of well-bore and the consequent reduction in well-productivity because of condensate build up, in a gas-condensate field is elaborated by means of the following figures:

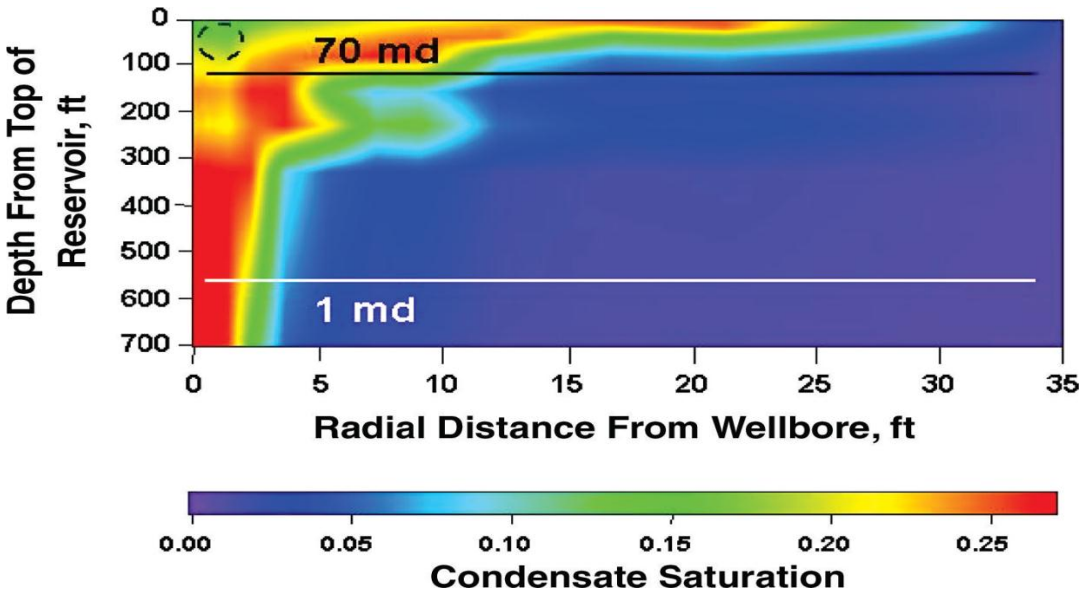

Figure 1-1 Example of a near well-bore condensate dropout [29].

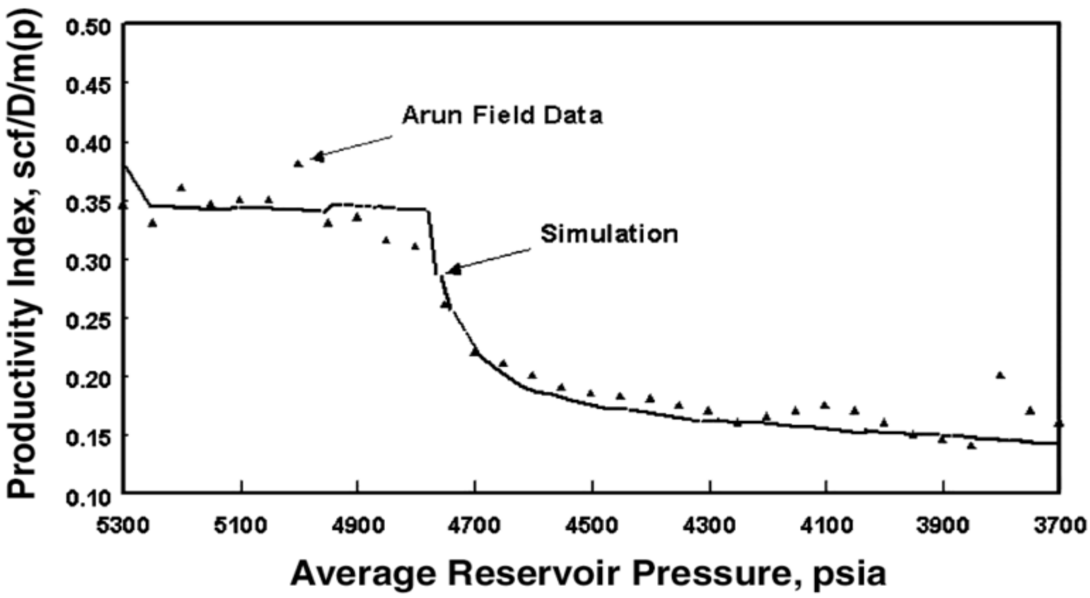

Figure 1-2 Example of condensate buildup causing well productivity reduction in Arun-field, Indonesia [30].

So, for the management of gas-condensate reservoir and to tackle this problem of condensate-blockage to improve productivity several methods are applied. These methods have both merits and demerits.

Second chapter is the theoretical background of gas-condensate reservoirs. Brief explanation of reservoir-fluids is provided with special attention to gas-condensates, their phase envelope, fluid properties, lean & rich condensates etc. Phase-behavior of the gas-condensates reservoirs is explained using the pressure temperature diagram. PVT-properties of gas-condensates and the main laboratory tests used to get these properties i.e. constant-composition expansion (CCE) & constant-volume depletion (CVD) are discussed with detail. Then flow-behavior of gas-condensate reservoirs is explained for both buildup and drawdown. At last a section is also dedicated to briefly explain production and separation of gas condensates.

Third chapter is Gas-condensate production issues and literature review. Since production issues of gas-condensate reservoir depend on several well & reservoir parameters, in this chapter the most relevant of these parameters are identified, briefly explained and their impact in condensate blockage has been quantified using different case studies from the literature.

Fourth chapter is the Production optimization strategies. Different strategies might be applied to avoid condensate blockage or to mitigate the blockage. These can be Pressure maintenance e.g. Gas cycling, CO2 & N2 injection etc., Productivity improvement via horizontal wells, hydraulic fracturing etc., Chemical injection e.g. for changing wettability of rock. All strategies are described and discussed with help of case studies and field cases from technical literature to suggest which strategy is best for a given gas-condensate reservoir.

Fifth chapter is the Discussion and Conclusion. All the production issues of gas-condensate fields are summarized here, and correct strategies along with their pros & cons to optimize production from different gas-condensate reservoirs & fields are suggested.

2. GAS & CONDENSATE THEORITICAL BACKGROUND

2.1 Overview of hydrocarbon reservoir fluids:

The petroleum based underground reservoirs basically consist of naturally-occurring long chain organic hydrocarbons, which possess a multiphase behavior over varying range off pressure and temperatures. In broader terms, petroleum-based reservoir, we can categorize into gas and oil reservoirs, which can be then further classified on basis of:

- hydrocarbon composition of product
- Initial temperature & pressure of reservoir
- Temperature & pressure at surface production, etc.

It is convenient to represent the conditions of occurrence of these multi-phase mixtures on phase diagrams, one such phase diagrams is the pressure-temperature phase diagram.

2.1.1 Pressure-temperature diagram:

Characteristic pressure-temperature representation of multi-phase system having specific overall-composition is depicted in figure 2.1, hydrocarbon system inside these reservoirs and for the description of the behaviors of such reservoir fluid mixtures.

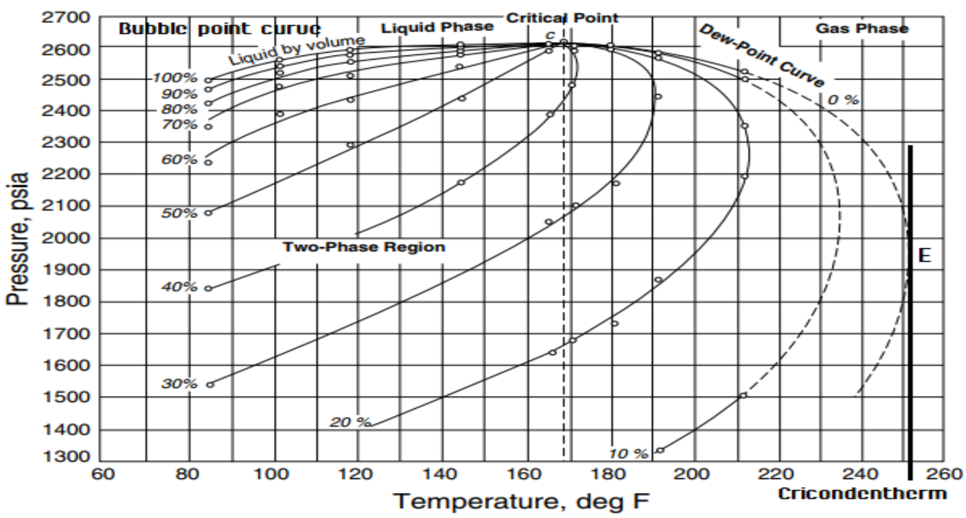

Figure 2-1 Pressure & temperature diagram for multiphase system [8].

The major variables on this diagram are described as under:

- **Cricondentherm (Tct):** is basically the maximum range of temperature above which the liquid condensate stops to exist irrespective of value of pressure, point E on the diagram is the point which represents (Tct) and corresponding pressure at such a point is called cricondentherm-pressure (Pct).
- **Critical point:** is such state of pressure & temperature, for which all the intensive properties of gas and oil multicomponent system becomes similar which is shown by point C on phase diagram. The Pressure & temperature values at critical point are called as critical pressure (Pc) and critical temperature (Tc) of the multicomponent mixture.
- **Bubble-point curve:** is that curve which divides liquid-phase region & two-phase region.
- **Dew-point curve:** is curve that separates the vapor/phase space & two-phase region.
- **Phase envelope (two-phase section):** Region is enclosed by dew-point curve & bubble-point curve, and at this region; Gases & liquids coexist in equilibrium.
- **Quality lines:** These are dashed lines inside phase envelope and are employed to describe values of pressure & temperature of equal volumes of liquid.

2.1.2 Classification of the Petroleum Reservoirs:

2.1.2.1 Oil reservoirs: When the reservoir's temperature is below than that of critical-temperature of reservoir fluid, then it is categorized as oil reservoir which can be subcategorized on basis of reservoir-pressure as under:

- Under-saturated oil reservoirs
- Saturated oil reservoirs
- Gas-cap reservoirs

2.1.2.2 Gas reservoirs: When the reservoir's temperature is over critical-temperature of reservoir-fluid, then it is categorized as gas reservoir. These types of reservoirs are further categorized on terms of their phase-envelope factor and reservoir-conditions into following subcategories:

- Dry-gas reservoirs
- Wet-gas reservoirs

- Retrograde gas-condensate reservoirs
- Near-critical gas-condensate reservoirs

(1) Dry-gas reservoirs: The reservoir-temperature for dry-gas reservoirs over cricondentherm so reservoir-fluid is in gaseous phase. This mixture of various hydrocarbons basically exists in gaseous form in reservoir & also at near well surface facilities as the conditions for phase separation exist outside well. Water is only liquid associated with dry gas-reservoirs and the typical gas/oil ratio (GOR) values for dry-gas reservoirs are more than value of 100,000 scf /STB [8].

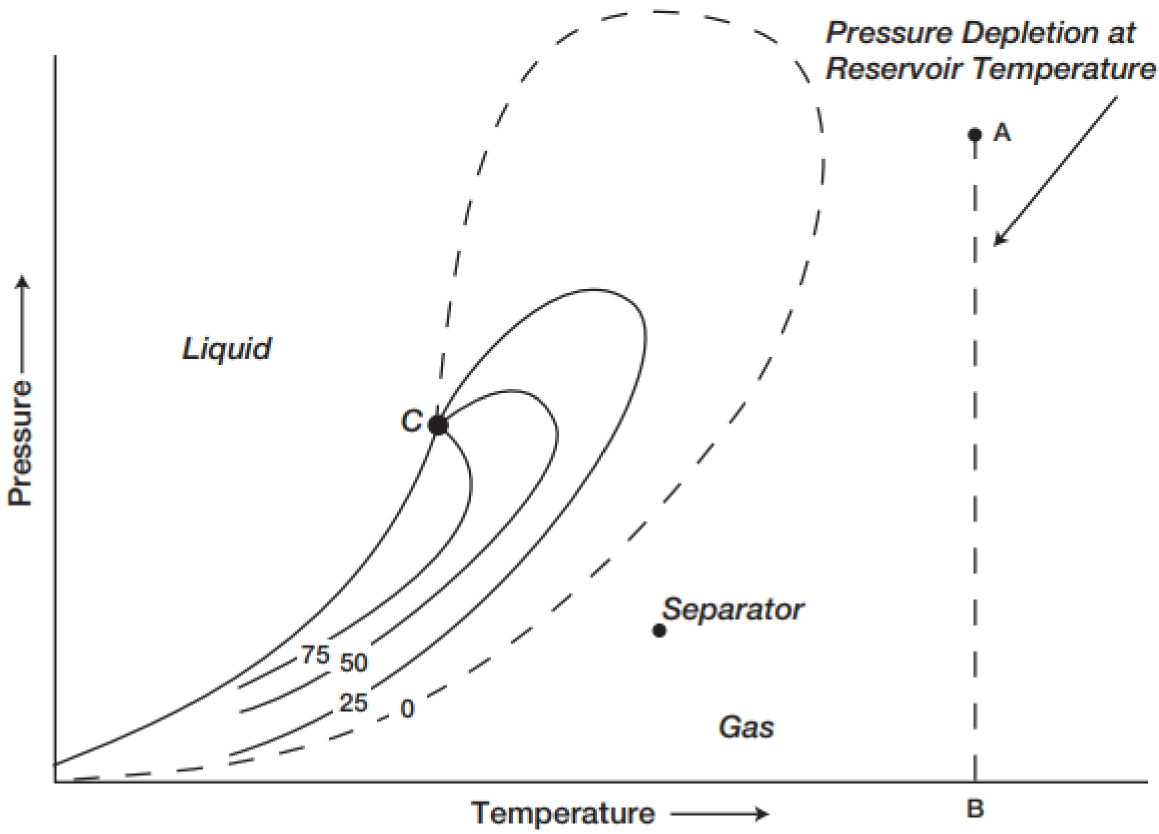

Figure 2-2 Typical phase-diagram of dry-gas reservoir [8].

(2) Wet gas reservoirs: The reservoir natural temperature is over cricondentherm temperature, so the hydrocarbon-mixture exists in form of gas. Before gas production at surface of the well, operating temperature & pressure of the surface lie in the two-phase mixture range, so liquid content is condensed out from the gaseous-mixture in separators. These reservoirs possess GOR values in-between 60,000-100,000 scf /STB and value of tank-oil gravity is above 60° API [8].

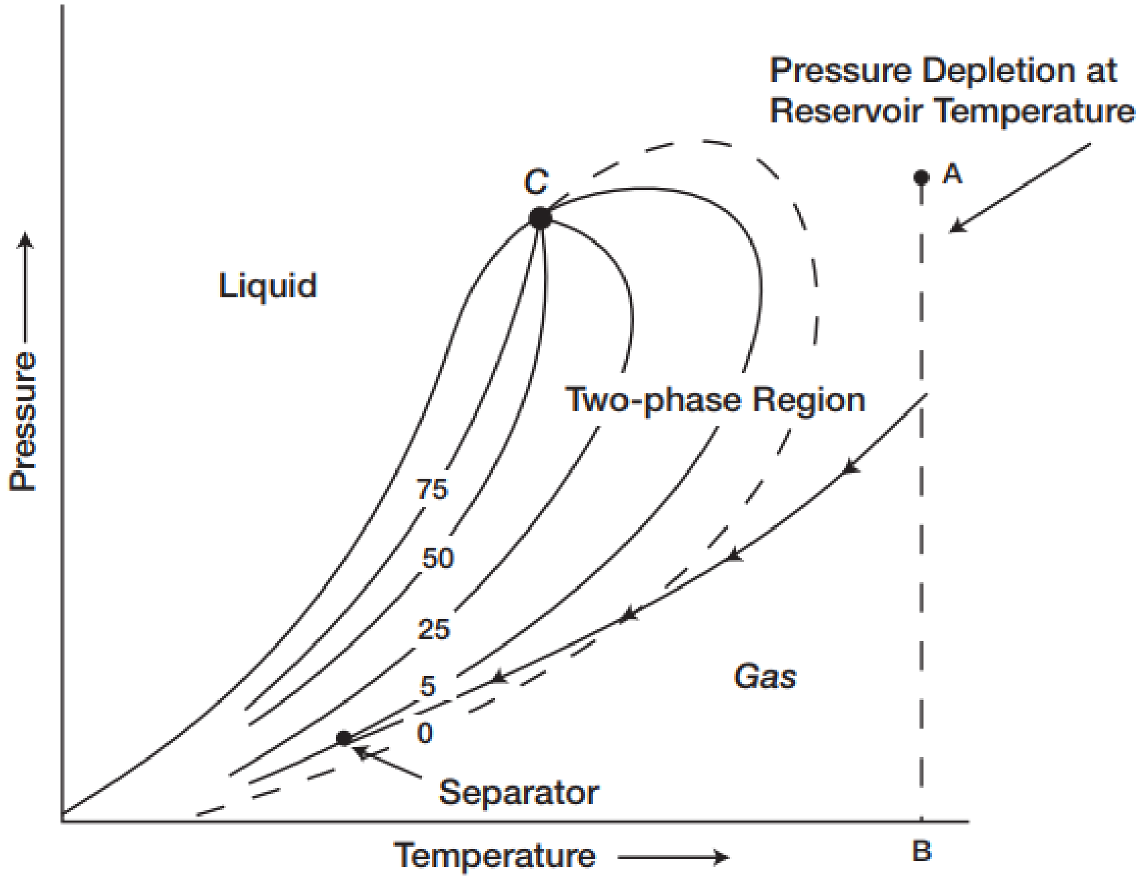

Figure 2-3 Typical wet-gas reservoir phase diagram [8].

(3) Near-critical gas-condensate reservoir:

For such reservoirs, temperature of reservoir is just at or near critical-point temperature; as a result, such a hydrocarbon-mixture is called a critical gas-condensate. The fluid of reservoir initially is in form of a gas, then following the isothermal decline path at unvarying pressure (1-3), the pressure-drops below dew-point temperature, and condensation rapidly starts to occur as the curve reaches point 2.

This is called retrograde condensation. Along the pressure decline path when the liquid stops to buildup and starts to shrink in contents, then such a reservoir moves from the retrograde conditions to normal-vaporization region as presented in figure 2.4 below.

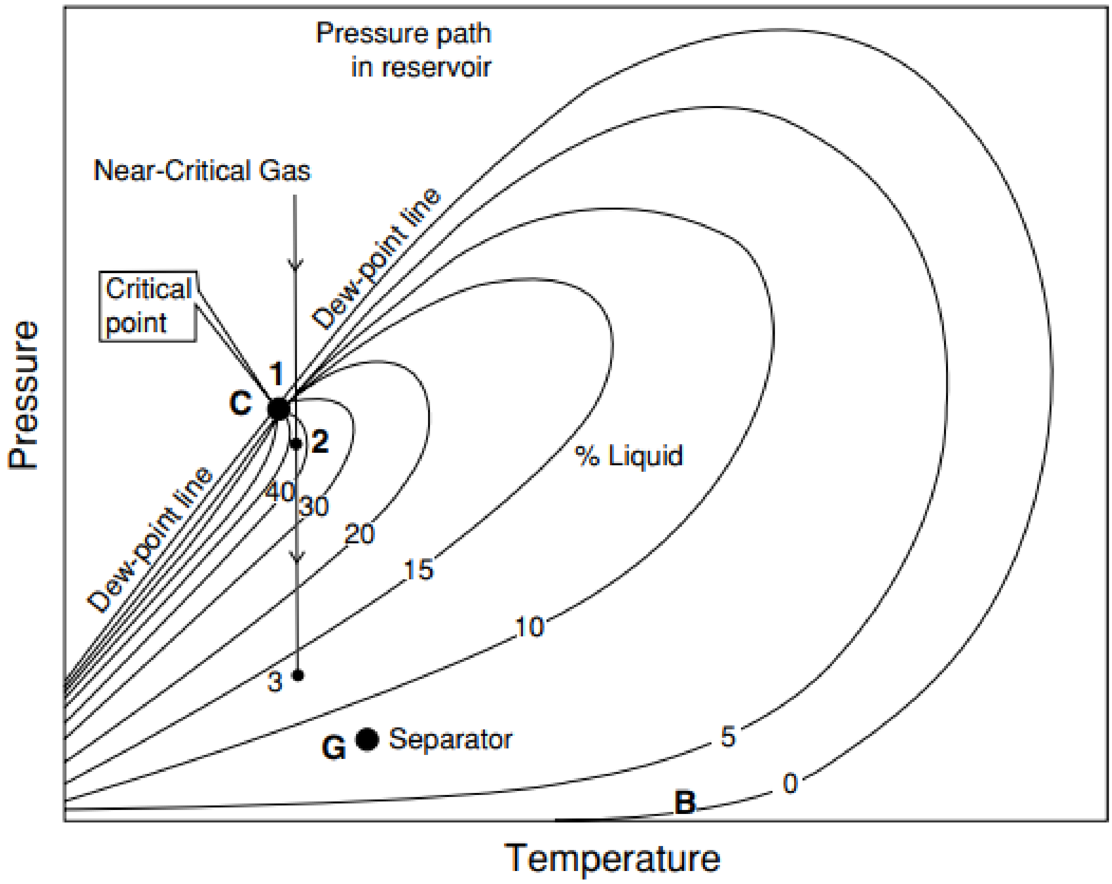

Figure 2-4 A near critical gas-condensate reservoir phase diagram [8].

(4) Gas-condensate reservoirs:

For such category of reservoirs, the operating reservoir temperature lies in-between critical temperature range and cricondentherm temperature of that reservoir fluid and condensate acquired in such conditions is categorized as retrograde gas condensate. From compositional view point the condensate consists of methane with small quantity of heavy components. Gas-condensates are peculiar because, upon pressure decline below dew-point, they generate a liquid phase.

2.2 Phase-behavior of gas-condensate:

The phase-behavior of condensate depicted in the pressure-temperature diagram, in figure 2.5. The initial temperature & pressure states of gas-condensate are illustrated by point 1 on phase-diagram and since pressure of reservoir is located above dew point, so reservoir-fluid exists in form of single gaseous phase. Pressure of reservoir then declines isothermally along gas production from an initial high pressure to an upper dew-point pressure recorded at point 2. As gas-condensate possesses both light and heavy components, originating in the gas-condensate, attraction between heavy components molecules dominates and liquid phase begins condensing rapidly. This condensation process continues, as the pressure decreases further, till the maximum liquid dropout limit is reached at point (3). Further reduction in the pressure results in a normal-vaporization process which continues to lower dew point at point 4 on the temperature pressure phase diagram pointing to the fact that all the liquid content has been vaporized and the state conditions at point 4 is wholly in vapor phase [8].

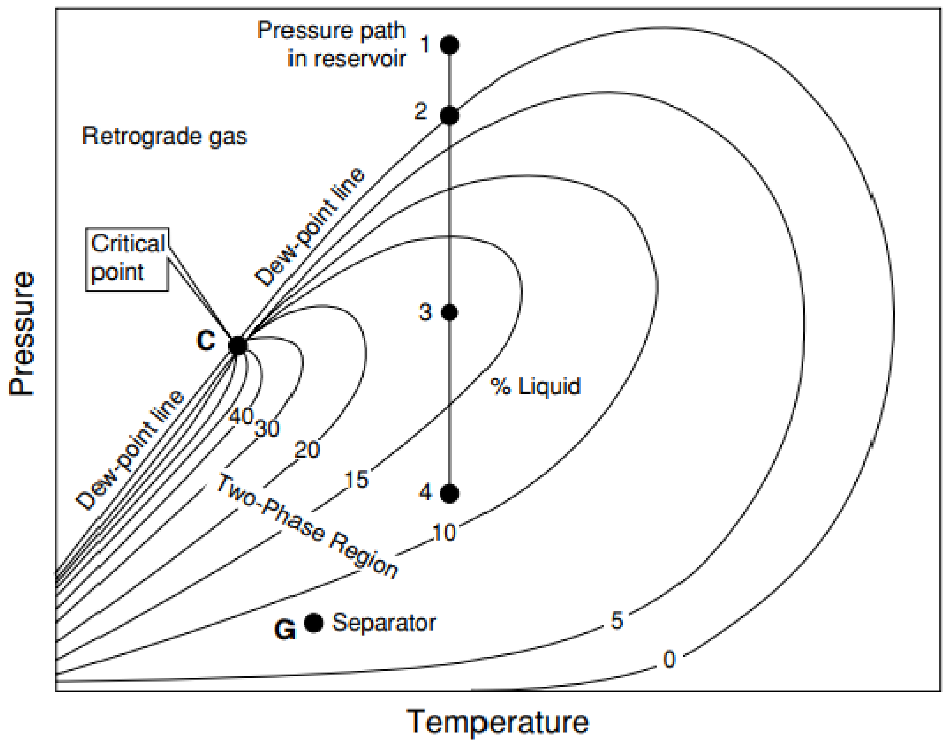

Figure 2-5 Gas-condensate reservoir phase diagram [8].

The condensation of gas into liquid phase with a pressure drop below dew-point temperature is shown by a curve commonly called liquid-dropout curve. Normally, of gas-condensate reservoirs, the condensed liquid volume seldom exceeds 14% to 18% of the pure volume of gas. Thus, liquid saturation is not large enough for the liquid flow; however in the area near to the wellbore region, the pressure-drop is considerably high, so enough liquid may accumulates having two-phase flow of both gases and liquids.

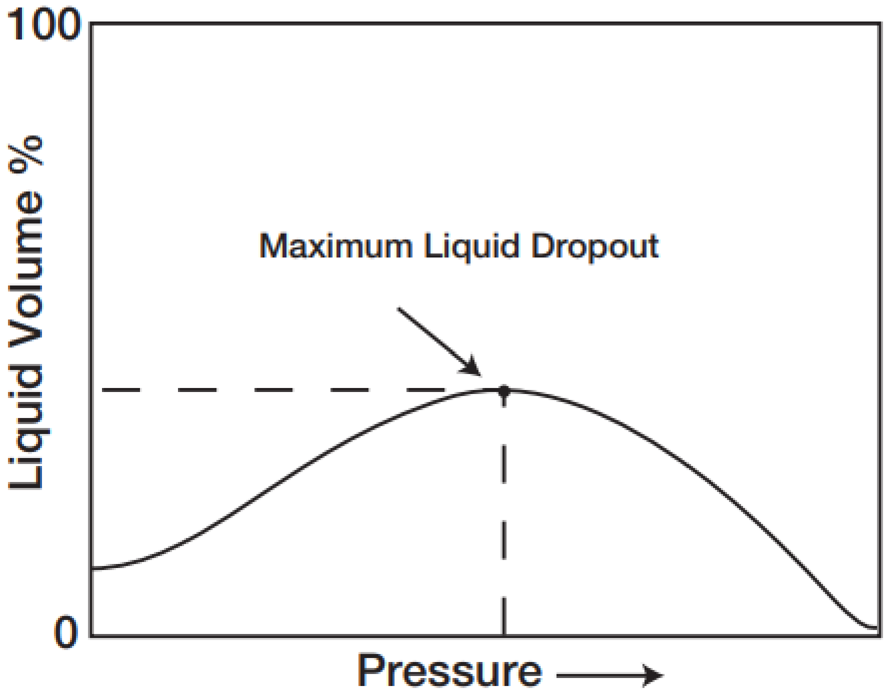

Figure 2-6 A typical liquid-dropout curve [8].

The content of liquid phase present in our reservoir just not dependent on the temperature & pressure but also on the chemical composition of fluid [4]. Based on this fact, there are mainly two categories of gas-condensates:

(1) Lean gas-condensate generates minor amount of liquids which are usually less than value of 100 bbl / million ft3.

(2) Rich gas-condensate produces a large volume of liquids, which are usually more than 150bbl /million ft3.

In real, no as such established limits for lean and rich gas-condensate mixture and these ranges are merely taken as indicators of range [4].

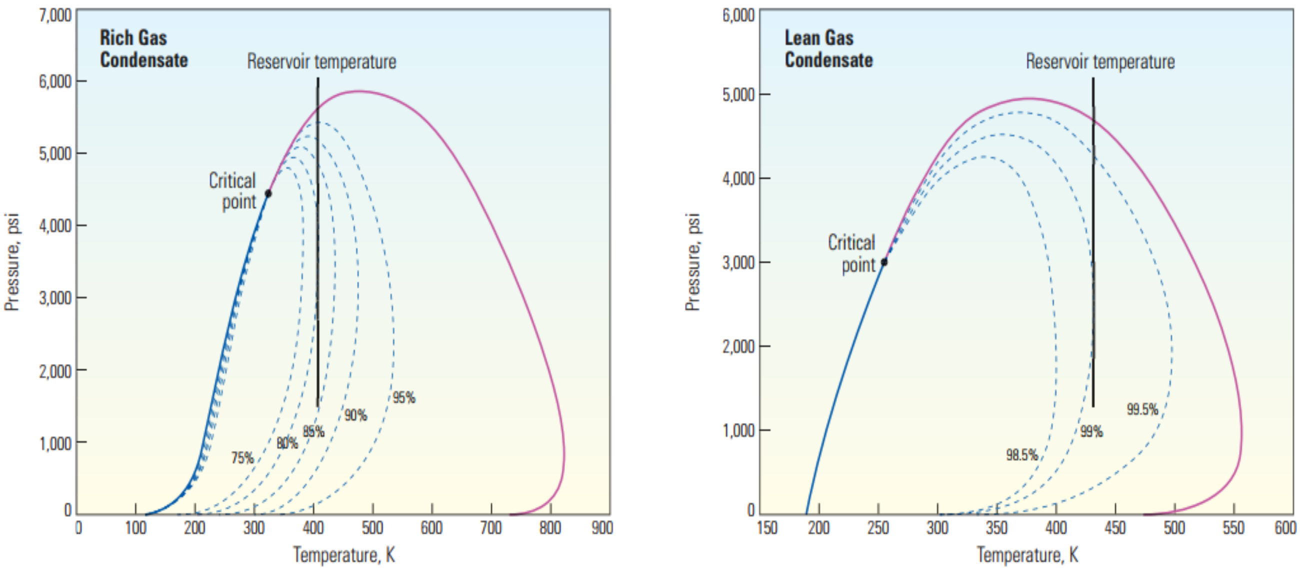

Figure 2-7 Rich gas-condensate (left) and lean gas-condensate (Right) [4].

2.3 Gas-condensate PVT-properties & measurement:

Gas-condensate reservoirs encounter compositional changes when reservoir-pressure decreases, making the system difficult to handle. So, to do proper fluid-characterization & understand the PVT-properties of reservoir-fluid, an equation-of-state (EOS) is employed. The PVT recorded data hence obtained is accurate and helping engineers in predicting reservoir fluids behavior and is used in reservoir simulation studies [31].

To retrieve PVT-properties of the condensate fluids, the first & foremost step is to collect representative samples of the condensate fluids. Samples could be collected at the subsurface, wellhead or surface. Each of them has own merits and demerits and standard measures to be followed. For case of gas-condensate samples, it is recommended to do surface sampling. In this sampling, the natural hydrocarbon-based fluid is made to flow through the phase separator at a steady and stable flow rate. In the separator, the oil & gas samples are taken at the same time after which the two samples are then recombined to producing GOR to get a representative reservoir-fluid composition. The collected samples are then conveyed in PVT laboratory for compositional analysis & standard PVT experiments. The results from PVT-experiments are then inputted into the PVT simulator, which characterize the fluid and assign individual properties to the components using an equation-of-state (EOS). The PVT parameters thus obtained might be employed in material balance calculations and numerical simulations [32].

Now the PVT behavior of reservoir-fluids is generally expressed by a set of formation-volume factors & solubility ratios. This set is called standard PVT properties. Alternatively, the PVT-behavior of reservoir-fluid can be also expressed by a set of mole fractions and densities, and this set is called as compositional PVT-properties. These both sets of PVT-properties are entirely equivalent. The standard set is more popular owing to routine measurement. The standard PVT-properties are the following [33]:

- **Oil formation-volume factor (Bo)** "is basically a ratio between the liquid phase volume at reservoir conditions to the same liquid sample volume at standard conditions."
  Units: [RB / STB] or [res.m^3 / std. m^3]
- **Gas formation-volume factor (Bg)** "is ratio of volume of gase phase at reservoir-conditions & volume of same gas sample at standard-conditions of temperature and pressure."
  Units: [RB / scf] or [res.m^3 / std. m^3]
- **Dissolved gas-oil ratio (Rs)** "is the ratio of the volume of surface gas to stock-tank oil in a reservoir liquid phase at reservoir conditions."
  Units: [scf/STB] or [std. m^3/std. m^3]
- **Volatilized oil-gas ratio (Rv)** "is the ratio of the volume of stock-tank oil to surface gas contained in a reservoir vapor phase at reservoir conditions."
  Units: [STB/MMscf] or [gallons/Mscf] or [std. m^3/std. m^3]

These standardized PVT-properties are computed as functions of pressure as a variable, by utilizing following collected data from PVT-experiments: Cumulatively produced gas Gp, Cumulative acquired oil Np, Gas z-factor, z-factor of two phases, liquid fraction volume of condensate, Constant-composition-expansion (CCE) & Constant-volume-depletion (CVD) are one of main PVT experiments performed on gas-condensate fluids [33]. The mechanism and details of these experiments are given as following:

2.3.1 Constant-Composition-Expansion (CCE):

Here, visual cell is taken, and an already determined amount of gas-condensate is loaded into it, at pressure above reservoir initial pressure. For achieving equilibrium, system is left overnight. The cell volume is then increased slowly to decrease the pressure stepwise, while T is maintained constant. After each pressure level system is first left to accomplish equilibrium and then volume is recorded. No condensate or gas is taken-out from experimental-cell during the experiment and chemical composition remains constant. Such an experiment is only applicable to gas-condensate reservoirs where pressure is above dew-point i.e. chemical composition is fixed. It also operates to the conditions near a production well in the condensate ring where steady state conditions could be assumed which implies a constant chemical composition [8]. The parameters recorded and measured during CCE experiment are dew-point pressure, compressibility, z-factor, the liquid dropout, gas density & relative gas-volumes [31].

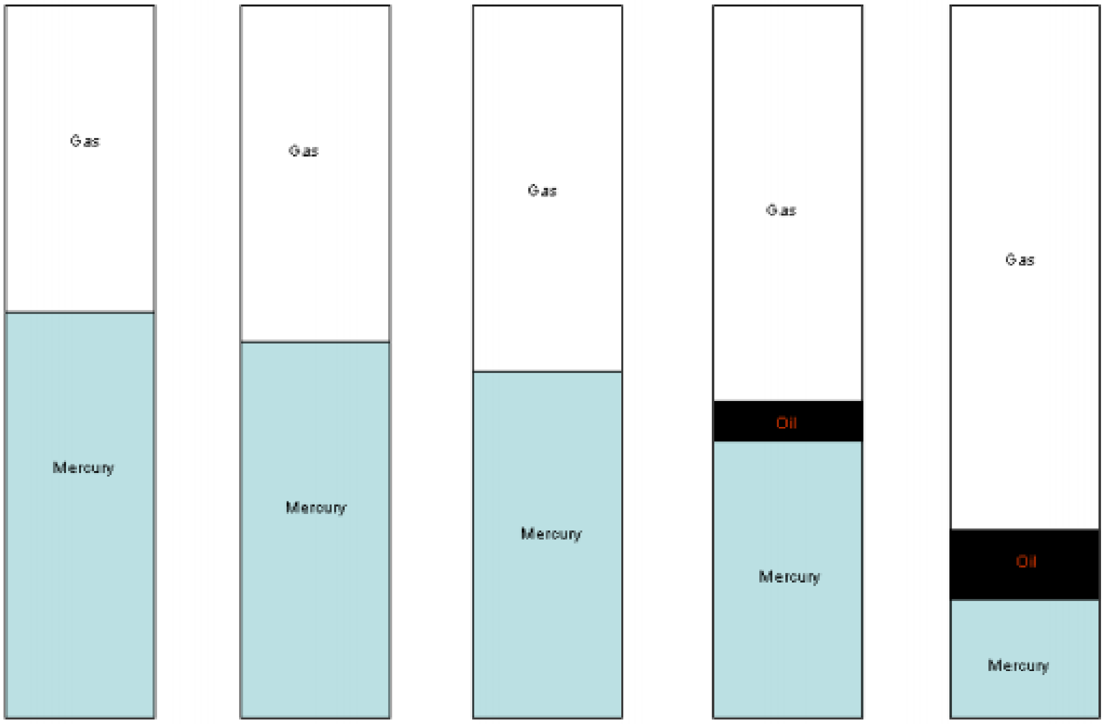

Figure 2-8 Graphical-representation of CCE experiment [8]

2.3.2 Constant-Volume-Depletion (CVD):

In experiment overall compositions vary during process. The assumption for gas-condensate system in CVD experiment is that; condensate is immobile. Dew-point of system is found from the CCE experiment. System is just brought just to its conditions of dew point after that multiple expansions are done by expelling gas at constant-pressure to the point where the cell volume levels to the volume at dew point. At each of the stage the volumes of gas & liquids and pressure are monitored and recorded. In addition, composition of expelled gas is also determined, and gross chemical composition is also determined by material balance meanwhile temperature is maintained constant throughout whole process and the assumption that phase of condensate remains immobile is valid only when condensate saturation level is below critical saturation level [8]. The quantities recorded during the experiment are: liquid-dropout, cumulative produced-fluid, gas density, gas z-factor and 2 phase z-factor [31].

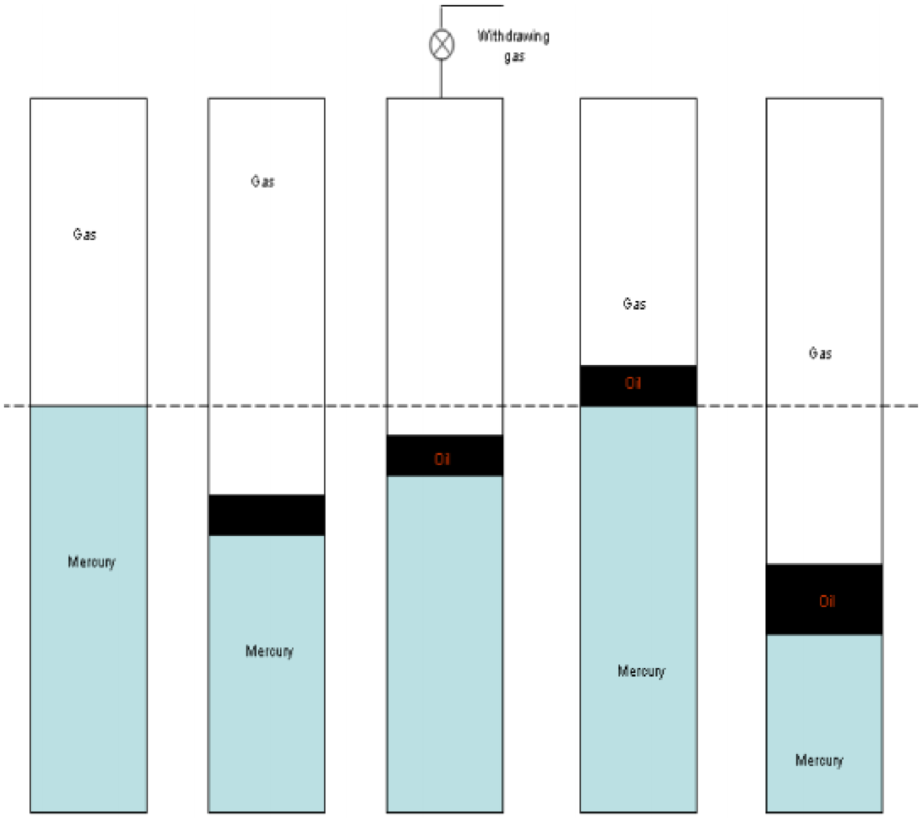

Figure 2-9 Graphical-representation of CVD Setup [8]

2.4 Behavior of flow of gas-condensate:

2.4.1 Drawdown Behavior:

Flow-behavior of gas-condensate reservoir sources is different from the reservoir values as compared to near wellbore region, mainly influenced by mobility and critical saturation of the condensate constituents. Far from wellbore the saturation level of liquid drop-out is quite low and it remains trapped in pores and pore throats owing to capillary forces, since the capillary action forces majorly favor the condensate to be in-contact with grains. Even for the rich gas-condensates the condensate mobility is insignificant away from wellbore. So the ultimate effects of dropout on the gas mobility are mostly negligible [4].

This situation is quite different in conditions near production well. As the bottom hole pressure declines below the dew-point, a pressure sink source is generated around wellbore area, where gas is drawn into the pressure sink and liquid drops out. After a short transient period, the accumulated liquid achieves a significant mobility and the condensate blockage mostly occurs owing to reduction of gas mobility in a production well for pressures below dew-point [4].

From previous literature, in 1996, Fevang et al. extensively suggested model for better understanding of flow of gas-condensate into the producing well from a gas-reservoir undergoing depletion as the steady state conditions of flow are achieved. Based on this model, flow in gas-condensate reservoirs can be characterized into three main reservoir-regions, although there might be situations when all these three regions may not be present. The two regions close to wellbore exist when the pressure at bottom hole is below pressure at dew-point. The third region exists away from well and occurs only when pressure of reservoir is above dew-point [13].

Region 1 is basically the inner near-well region where the saturation of condensate is higher than value of critical condensate-saturation level so both the condensate and gas-phases are in mobile state, although both have specific velocities. Here composition of flow is also constant, so all of required fluid properties can be easily approximated by using CCE. This region is largely responsible for loss of deliverability in gas-condensate wells, as permeability of gas decreased because of condensate-blockage. The area of this region rises with time and exists only when the bottom-hole pressure is below the dew-point [13].

Region 2 consists of region where condensate builds up, and here only gas-phase is mobile. Pressure in region-2 is lesser than dew-point but saturation of condensate is also below the critical-value, so we only have gas flow which majorly results in region of just condensate accumulation. The dropout of condensate in region-2 can be effortlessly approximated by CVD experiment that been corrected for water-saturation point. In addition, size of region 2 declines with time as opposed to region 1, which expands considerably over time [13].

Region 3 is outer region which lies far from well and here pressure is considerably above dew-point pressure. Here, only the original gaseous phase is present and condensate dropout is absent. The fluid-properties here can be effortlessly approximated by employing the CCE experiment. [13].

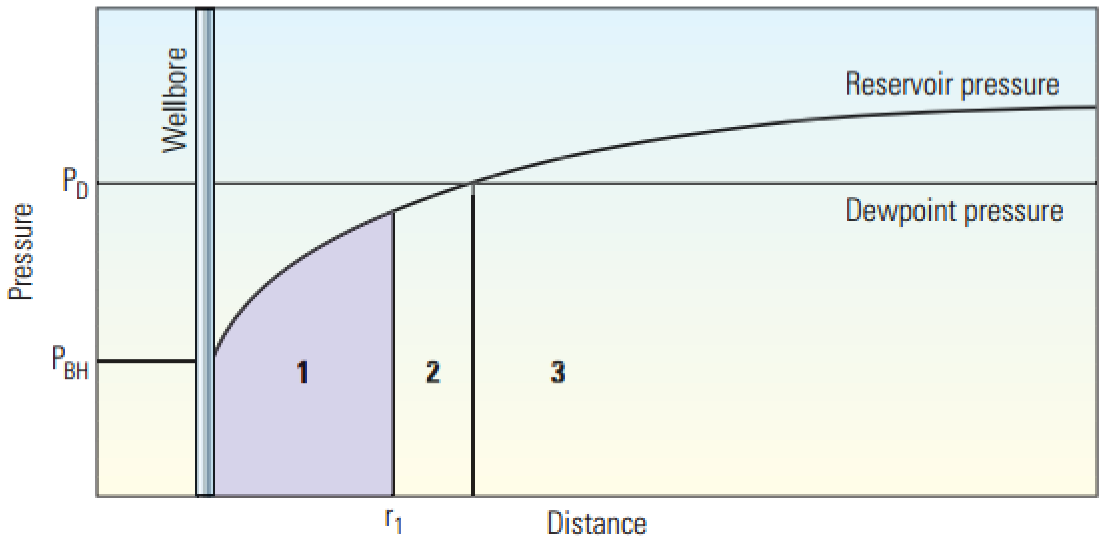

Figure 2-10 Three sections of gas-condensate reservoir [4].

Since the value of oil saturation (S_o), oil relative-permeability (K_{ro}) and oil mobility are all at maximum at region 1, so it's the flow-behavior of region 1 which dictates deliverability-loss of well due to condensate-blockage. So the relative permeability of oil at low oil saturations (near critical oil saturation S_{oc}) i.e. at region 2 & 3 are not relevant for condensate blockage. In case of rich gas-condensates oil saturations in region-2 can be somewhat more than value of Soc, even then value of relative-permeability of oil here is not that important as here oil-mobility is practically approaching zero value. So, for gas-condensate blockage phenomena region-1 is important region for all practical purposes [13].

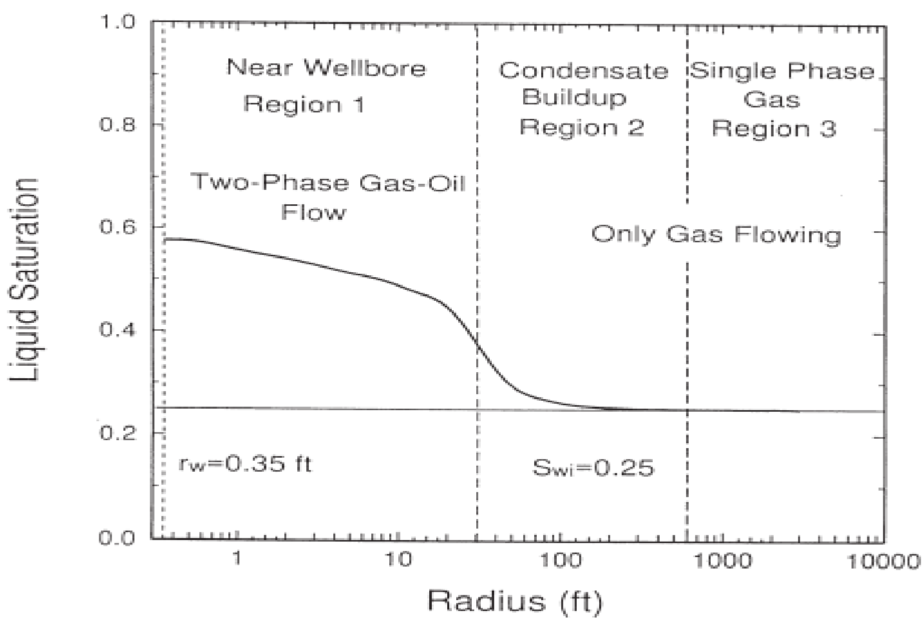

Figure 2-11 Three regions of flow-behavior in a gas-condensate well [13]

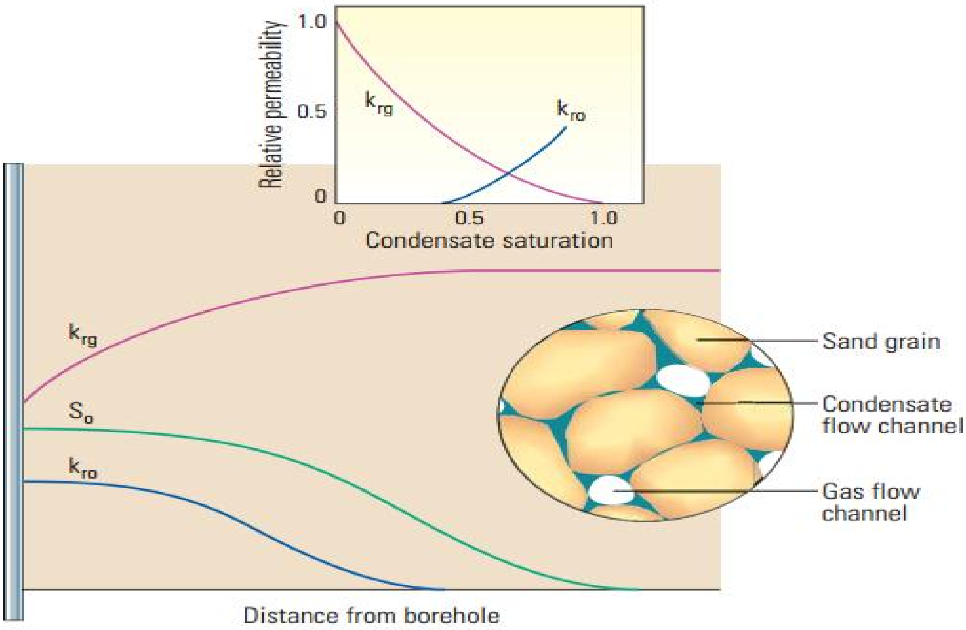

Figure 2-12 Condensate blockage and trends of oil saturation, relative permeabilities of gas & oil depending upon distance from the borehole [4].

2.4.2 Buildup Behavior:

During production from a gas-condensate reservoir the overall chemical configuration and nature of existence of gas-condensate varies considerably because this is depleted of heavy hydrocarbon-contents. If well is closed down, the condensate bank that will be formed around well area, is projected to evaporate again due to pressure build up, but it may not. Economides et al. (1987) in theoretical calculations estimated the conditions in which hysteresis effects will occur during the saturation of condensate. This means that based on the original PVT-properties of gas-condensate re-vaporization is expected due to buildup of pressure, but the accumulation of such condensate in the reservoir may preclude the reverse re-vaporization process [14]. The reason behind this is that below dew point separation of fluid into oil and gas phases occurs quickly, followed by the segregation of these phases in pores or on large scale. This slows down the reverse re-vaporization process and immediate contact between gas and oil phase is required to recombine them [4]. Roussennac (2001) found in a simulation study that if the production period is longer than a certain threshold, then the near wellbore fluid can change its behavior from gas-condensate to a volatile oil [5]. Similarly, Novsosad (1996) also concluded in his numerical-simulations studies that during the depletion phase from lean gas-condensate reservoir, the fluid near-wellbore changes its chemical behavior from gas-condensate to near-critical retrograde gas and later to volatile oil [6]. In addition, if gas-condensate system is near-critical, then behavior during pressure depletion is more complicated. In this case double retrograde condensation can occur generating two liquids rather than a single liquid phase [15].

2.5 Gas-condensate production and separation:

The main priority of production from a reservoir of gas-condensate is to acquire a gas in single-phase with the heavy constituents fully dissolved in gas phase. This is crucial for the recoveries of both, gas and the condensates. Because, if pressure plunges below dewpoint pressure would cause in two phases so:

- Gas production will fall due to condensate buildup in near-wellbore region
- The valuable heavy ends are trapped within reservoir

Moreover, condensate will also form in wellbore area because of variations in pressure and the temperature conditions. If gas lacking the sufficient energy or pressure to carry the condensed liquid to well surface, it will direct to liquid loading or fallback in the wellbore. This fallback of the condensations would cause increasing in liquid percentage in wellbore and eventually might cause restriction of gas production [4].

Several configurations are employed for separation of natural-gas condensate from raw natural-gas. A general schematic diagram of flow is exemplified in figure below. The feedstock from well is firstly fed into cooler unit which considerably lowers temperature of gas below dewpoint of such hydrocarbons. So large-amount of hydrocarbon condensates will be condensed at that point. This liquid condensate, water and gas mixture afterwards sent to very high-pressure phase separator known as knockout drum, where gas and the water are separated and extracted.

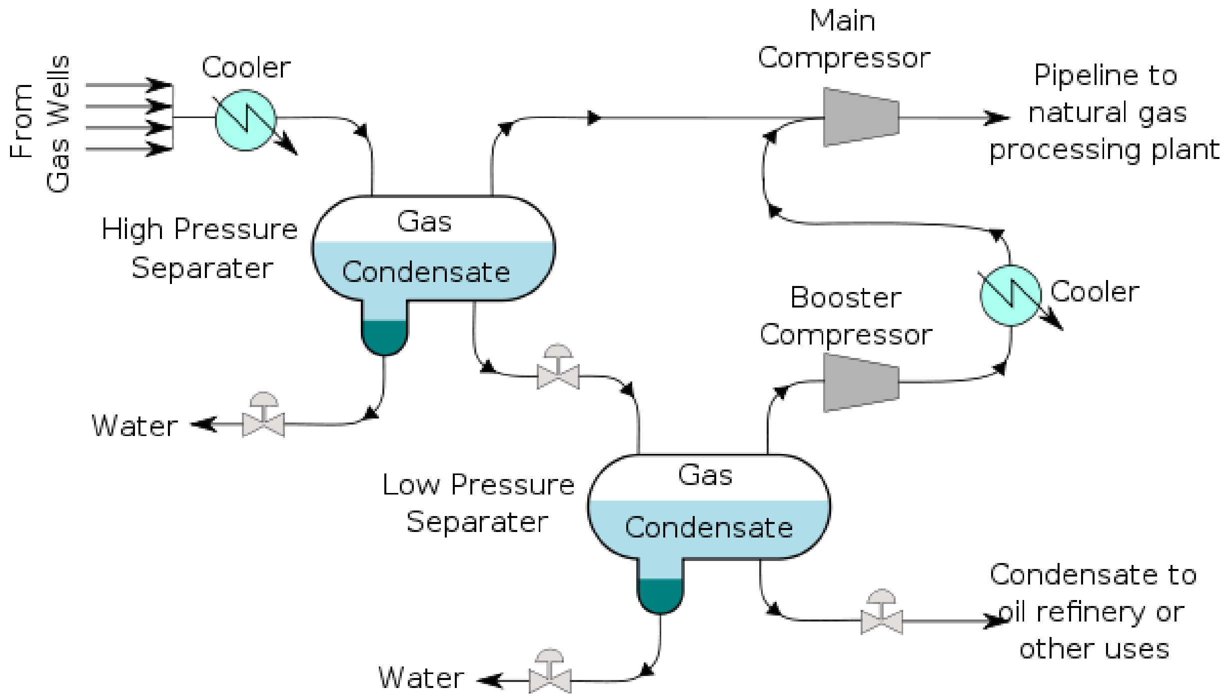

Figure 2-13 Flow-diagram of gas-condensate separation from gas stream [34].

The gas then is sent off to main gas-compressor and remaining gas condensate from high pressure-separator is passed through control-valve that is monitored and controlled by throttling, to a low-pressure separator. Pressure is further reduced across control valve hence condensate undergoes a partial vaporization. From here, low pressure condensate is sent off to oil refineries or for other applications. Natural gas from low-pressure separator is passed a booster compressor and then to main gas-compressor which raises the gas pressure to the requirements of pipeline-transportation of gas to raw natural-gas processing facility, where the excess water, acidic-gases and impurities are removed from natural gas which then sent for relevant applications [34].

3. GAS-CONDENSATE PRODUCTION ISSUES & LITERATURE REVIEW

Condensates and gas are obviously the two main products we obtain from a gas-condensates reservoir. Typical recoveries for these reservoir fluids are 20 to 40% for the liquid and 60 to 80% for the gas [16]. Both, gas and the liquid are important for us and as liquid is comprised of heavy ends, so is more valuable in regions which are far from gas transport systems [17]. Hence the ideal target of production optimization from gas-condensate reservoir is that to prevent lessening in gas production owing to condensate blockage, and to bring all the heavy ends to surface.

3.1 Objectives and Methodology:

Gas-condensate reservoirs show complex-phase and flow-behaviors because of condensate-banking at low pressures in near wellbore-region. Good understanding about how condensate banking influences the well-productivity and fluid compositions is vital to improve production strategy, to reduce effects of condensate-banking also to improve gas recovery. Condensate banking affects effective-permeability of gas, and also leads to loss of heavy-components at surface. These effects hinge on many well and reservoir-parameters [18]. Intended motive is: identify these parameters based on case studies from the literature and perform a critical-analysis of them. Case studies are scrutinized for identifying most crucial parameters for production-optimization and to classify different reservoirs, suggesting the proper production strategy for each of them.

3.2 Literature Review:

The productivity loss because of condensate-blockage is high. The loss could be so high as factor of two or four as described in the case studies of Afidick et al. and Barnum [9], [10]. Even in case of extremely lean gas-condensate reservoir as in the Arun-field case study, productivity maybe decreased by factor of two when pressure drops even below dew point [9]. Similarly, Fevang et al. highlighted and addressed loss of well-deliverability through gas-condensate reservoir modeling. They observed that loss of deliverability was due to near wellbore condensate-blockage and that it depended upon PVT properties, relative and absolute permeabilities, and how production is taken from the well [13].

So, production optimization from gas-condensate reservoir depends on many well, and reservoir-parameters, these include:

- Relative –permeability of gas & condensate phases

- Absolute-permeability of the reservoir-rock
- Fluid properties, condensate to gas ratio
- Wettability preference of reservoir-rock
- Production flow rate
- Production tubing size
- Bottom-hole pressure
- Declining pressure in a slow or fast manner to a given bottom-hole pressure etc.

These parameters got special attention using laboratory work, genuine field data and reservoir simulations to assess their importance for production-optimization and to suggest strategies for mitigating effects of condensate-blockage on productivity. Below is the overview of many case studies from literature showing importance of these parameters in relation to the productivity from gas-condensate reservoirs.

3.3 Case Studies

3.3.1 Relative Permeabilities:

Relatively permeability is key factor controlling deliverability of gas-condensate well, and relative-permeability is directly impacted by condensate-accumulation [18]. The condensate liquids which are formed throughout reservoir have different mobility behavior, where mobility is ratio of relative-permeability to viscosity. Away from wellbore, liquid becomes immobile, owing to low-saturation and capillary-forces. Whereas in near-wellbore zone the mobility increases because the saturation gets higher than critical value. So, gas and the liquid would struggle for flow towards well and so relative-permeability of each fluid have pivotal role in affecting production [19]. In general gas has a higher mobility than oil because their viscosity is lower than oil. But mobility also depends on the relative permeabilities in multiphase system. Away from the wellbore (region 2 & 3) gas is the only mobile phase since oil saturation is below the critical oil saturation. But near the wellbore oil saturation is higher than than the critical oil saturation so it's mobility becomes comparable to the gas phase, and that is where both the mobile phases start competing for flow and affect the production.

Alireza et. Al. in 2016 conducted single well simulation study to quantify pressure drop owing to condensate-blockage based on variations of relative-permeabilities in near wellbore-area. A single-well model with homogeneous property was performed using different constraints and property ranges. Basically, four reservoir qualities were used with different KH values i.e. 600, 1500, 4000 and 12,500 md-ft values. After running the simulation, the observations were increased oil saturation and decreased gas relative-permeability in near wellbore-region leading to decreased productivity index [17]. The oil saturation profile and gas relative permeability are for the lower permeability case (600 md-ft) are shown in the figures 3-1 and 3-2. It is very evident from these figures that gas relative permeability is highest in the regions far from the wellbore and lowest in the near wellbore region. This implies that condensate bank reduces the relative permeability of gas in the near wellbore region.

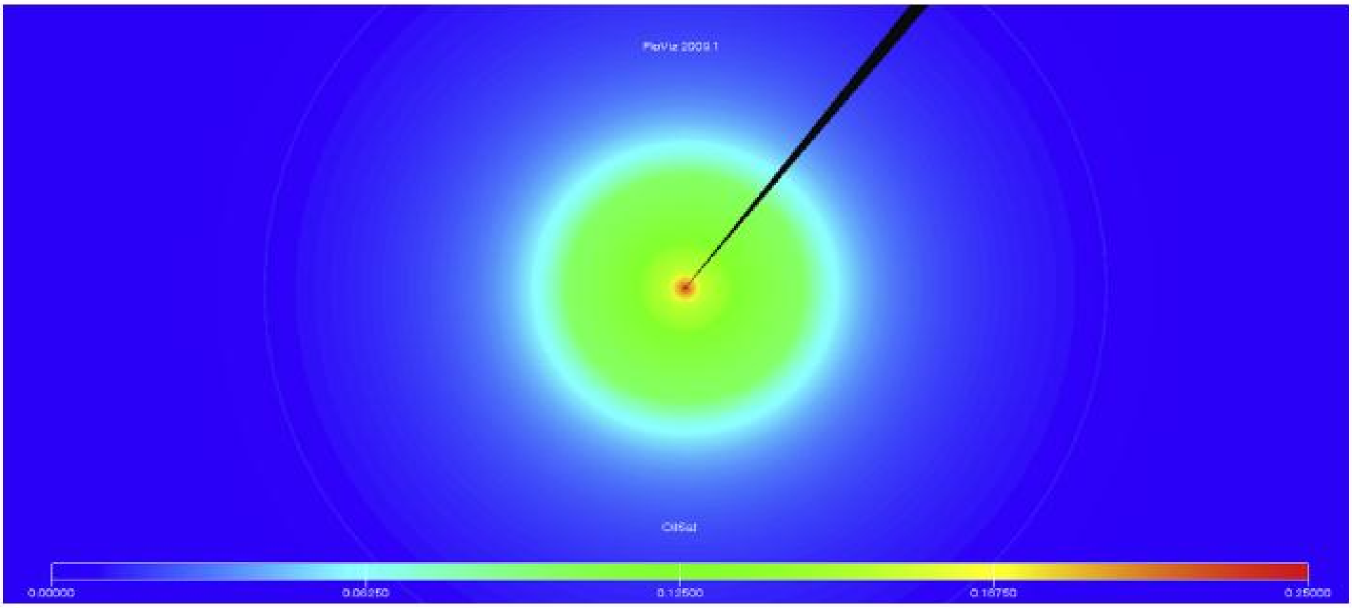

Figure 3-1 Oil saturation profile [17].

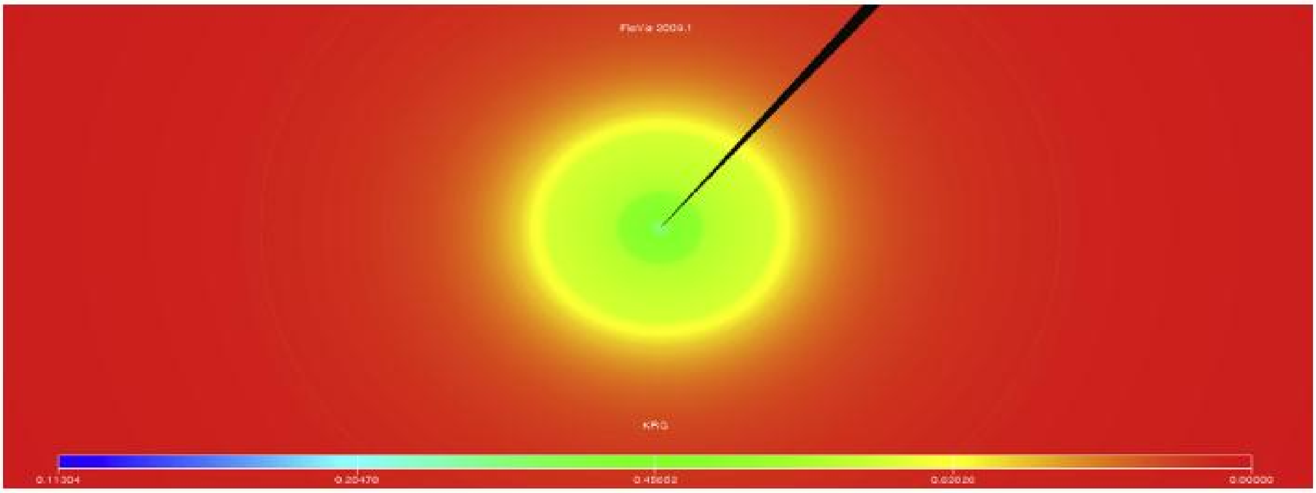

Figure 3-2 Gas relative-permeability [17].

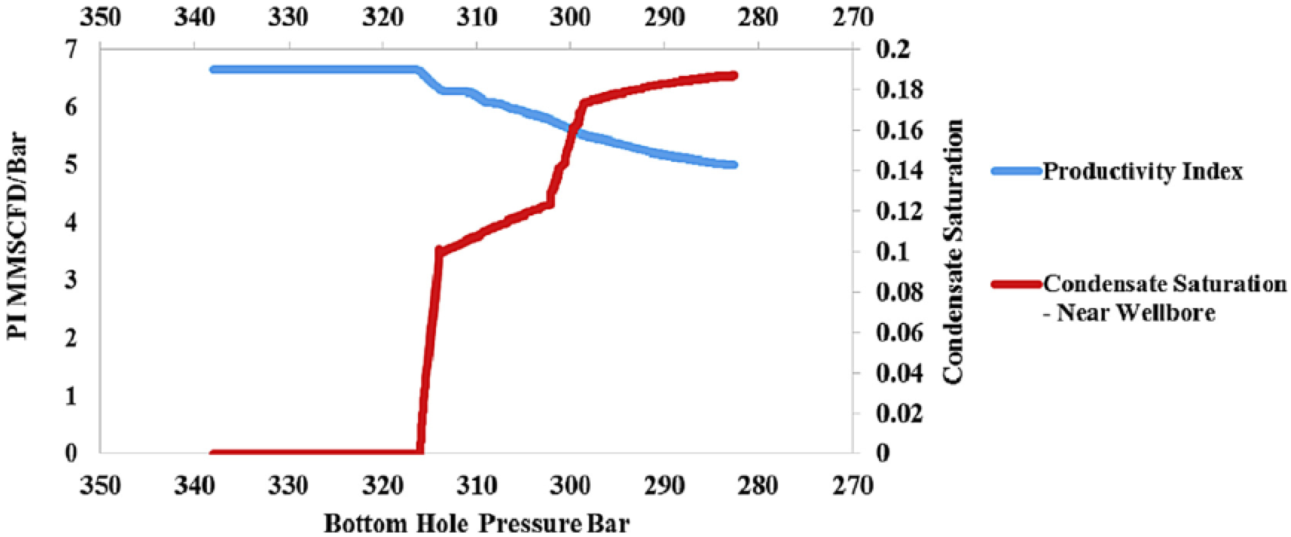

Figure 3-3 Condensate-blockage effects upon Productivity-Index – depiction of oil-saturation in near-wellbore area [17].

3.3.2 Absolute permeability of reservoir:

Down-hole pressure reduces more swiftly, and condensate-dropout is more around wellbore for low-permeability reservoirs compared to higher permeability reservoirs for alike production schedule [22]. A study by Barnum and co-fellows, suggested that lessening of gas production is more noticeable in reservoirs having kh less than 1000mD [10]. How much condensate-dropout is production problem hinges on ratio of pressure drop experienced inside reservoir to total pressure-drop from relatively far areas of reservoir to control point at the surface. It means that as pressure drop in a reservoir of low kh is significant then any additional pressure-drop due to condensate-blockage will be very significant for the well-deliverability. Conversely, in a reservoir of higher kh as there is less pressure-drop within reservoir, hence additional pressure-drop has a small effect on well-deliverability. As a general guideline, condensate blockage can be assumed to double pressure drop in reservoir while keeping flow rate constant [4].

In a compositional-model, reservoir-simulation study Y.H.Seah et al. quantified effect of absolute permeability of reservoir on production from gas-condensate reservoir. Many simulation studies were done for comparison condensate saturation-profile, gas-rates, and liquid-production rates for 4 different reservoir permeabilities: ultra-tight reservoir having k=0.001 md, tight-reservoir with k 0.1 md, low-permeability reservoir 1 md, and also high-permeability reservoir with k 1,200 md. Anisotropy ratio of 0.1 and porosity of 10% was taken for all 4 reservoir types. Results showed, gas-condensate production is lowermost for the ultra-tight reservoir and negligible liquid-dropout in high-permeability reservoir. This is because ultra-tight reservoir inhibits flow of gas, and condensates while high-permeability reservoir has good formation connectivity, due to which gas & liquid phases flow easily to the producing well and eventually to surface [20].

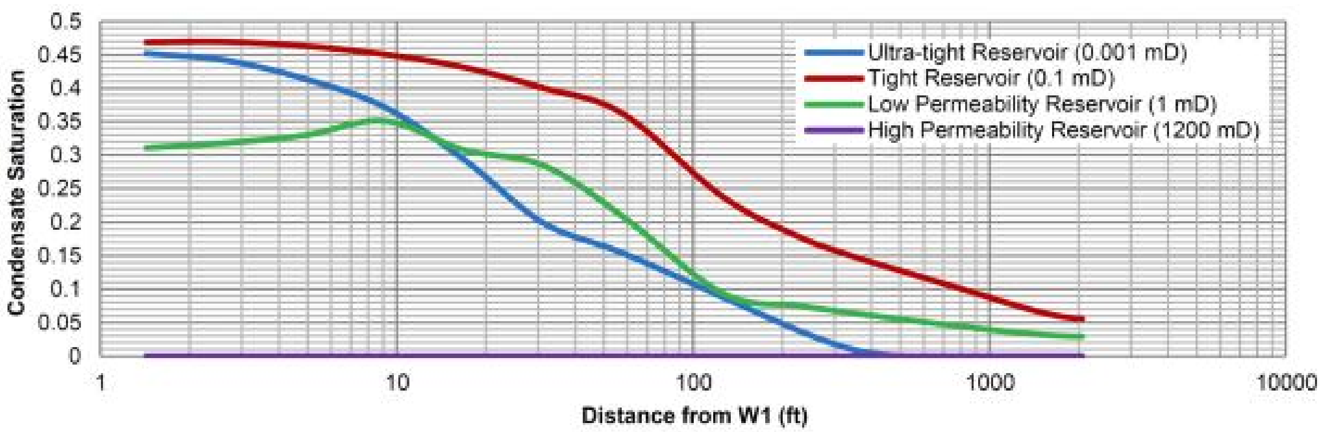

Figure 3-4 Profile of saturation of condensate different permeabilities gas-condensate reservoirs [20].

3.3.3 Fluid properties: Rich versus Lean-Gas Condensate

Fluid properties contribute particularly crucial part in gas-condensate reservoirs. For instance, condensate to gas ratio is important for estimation of sales potential of liquid & gas, which are needed for sizing the surface-processing facilities [4]. Medium-rich to rich gas-condensate reservoirs are more attractive due to more revenue generation and profits because of presence of valuable heavy ends, which makes the gas projects attractive. But if medium-rich to rich gas-condensate reservoirs have low absolute permeability then they present potential production problems as they are characterized by lower achievable gas rates, higher drawdowns and higher liquid dropout which means we get less heavier components on surface [21]. In case study several compositional-simulation studies were done by Y.H.Seah et al. to compare condensate saturation-profile around wellbore for varying gas-condensate compositions and maintaining other parameters constant. For investigation purpose, data of 4 gas-condensate fields was used with constant gas flow-rate of 2 MMscf/Day. Results showed: richest gas-condensate A displays highest quantity of liquid-dropout around wellbore and conversely leanest gas-condensate D displays lowest amount of liquid-dropout around wellbore [20].

Gas condensate	CGR (stb/MMscf)	Dewpoint pressure (psia)	Reservoir temperature (°F)
A	161	4767	340
B	87	4298	200
C	48	4028	251
D	27	3440	251

Figure 3-5 Properties of fluid for condensates A, B, C and D [20].

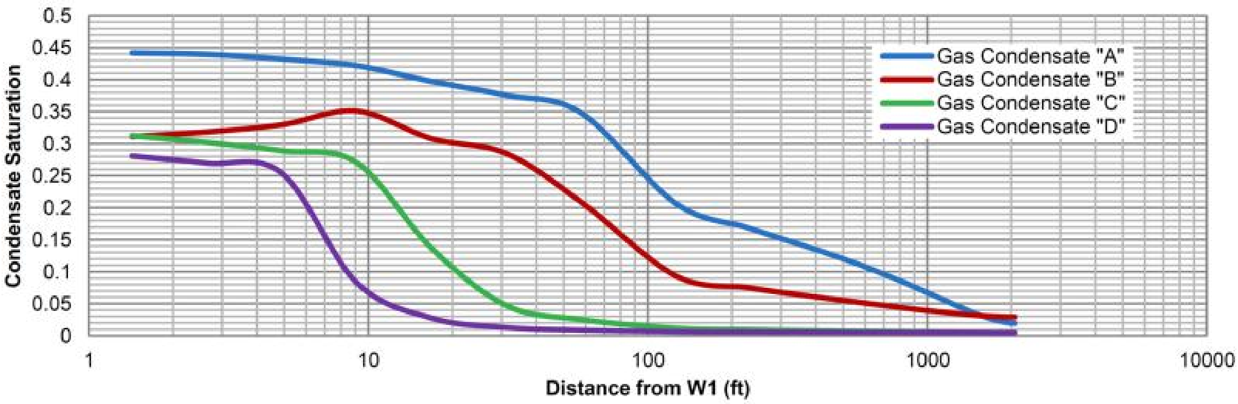

Figure 3-6 Saturation profiles for condensates A, B, C and D [20].

3.3.4 Wettability:

Wettability of reservoir-rock neighboring wellbore is also important parameter concerning production from gas-condensate reservoir. Most of mineral surfaces such as quartz, calcite & dolomite prefer to be wetted by liquid, but some solids also prefer gas wetting. Fluorinated compounds like Teflon surfaces are gas wetting [4].

So, need is to quantify upshot of wettability upon production from gas-condensate reservoir. This was done by Mohammad Sheydaeemehr et al. examining consequence of wettability-alteration on gas-condensate production augmentation in field. To study, radial single well compositional-model was constructed, and fluid and reservoir data were used from one of world's largest gas-condensate fields in the Middle-East located in southern-Iran. Three different relative-permeability curves were taken in model to embody three various wettability states. The results displayed: field gas-condensate cumulative-production highly improved through varying wettability preference of reservoir-rock from liquid-wetting to intermediate or gas-wetted by fluctuating relative-permeabilities for treating radius around 5m surrounding wellbore. Also, condensate saturation was decreased around wellbore and increasing the bottom-hole flowing pressure & productivity index [23].

3.3.5 Gas flow rate:

Apprehension regarding gas-condensate reservoir is remaining condensate jots in reservoir and the decline in the gas productivity, which is more noticeable as production rate increases [25]. There are some additional relative permeability affects in near-wellbore region owing to high gas velocity and high viscous forces. These effects are linked with the gas rate. Capillary number is ratio of viscous-forces to capillary forces. Conditions of high velocity or low interfacial-tension refer to high capillary numbers which means that viscous forces are dominating. So, relative-permeability for gas, is , higher at elevated flow-rates compared to low flow rates. At higher flow-velocities even, near wellbore, we have another effect called the inertial effect or Forchheimer-effect which decreases gas relative-permeability a bit [4]. So, deliverability of gas-condensate reservoir is highly influenced by communication of viscous-forces, capillary-forces and inertial forces near wellbore. These forces compete each other as pressure changes during the life of reservoir [26]. The overall balance of said forces controls deliverability of well [27]. Formation of condensate-bank near wellbore has harmful effects on the gas flow-rate and can be recognized as additional skin-effect. Mobile or fixed condensate-blockage in near-wellbore region results in reduction of imposed area to gas, contributing in additional skin-factor [28].

In study A. Hashemi and fellows explored dependence of skin to flow-rate in gas condensate-reservoirs through simulation-approach. Radial synthetic-reservoir compositional-model developed through use of fluid properties, rock properties, and well data from real gas-condensate field in southern-Iran. Findings were: increasing trend relating total skin factor (mechanical skin + condensate skin) versus flow rate. The trend is linear up to a critical production rate, and by increasing flow rate further effect of capillary-number compensates for unfavorable effect like that of non-Darcy flow, so rate-dependent skin decreases. In low-permeability reservoirs this critical flow rate happens at a lower rate [24].

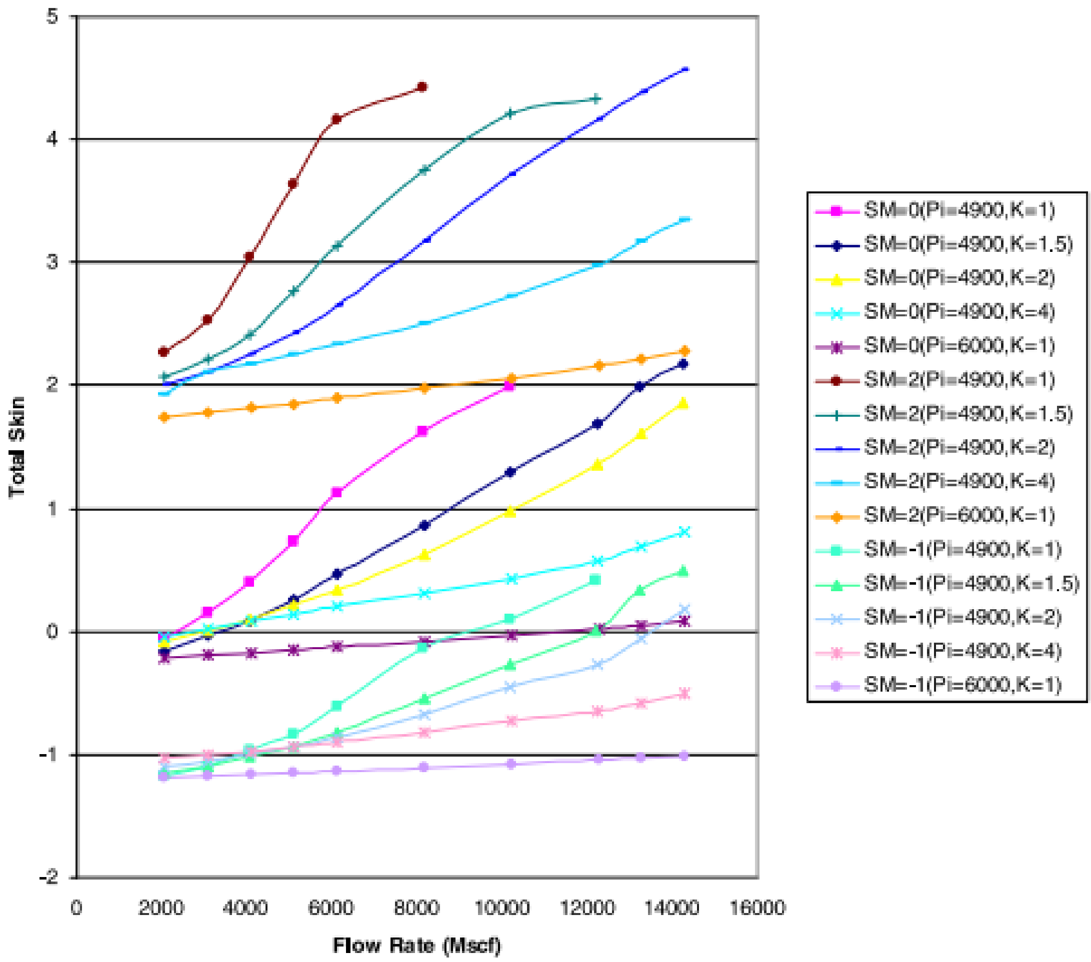

Figure 3-7 Rate-dependent skin tendencies in different permeabilities, initial pressures, Swi= 0.153 [24].

4. PRODUCTION OPTIMIZATION STRATEGIES

Gas-condensate reservoirs are source of large gas reserves and hence are of supreme importance owing to the increased energy need of the world. Arun field (Indonesia), Cupiagua field (Colombia), North field (Qatar), Shtokmanovskoye field (Russia) are some of world's largest gas-condensate fields [35]. Condensate banking is a big problem as it decreases gas & condensate recoveries, decreases well productivity & ultimately affects the recovery factor. Condensate banking is mainly a near wellbore phenomenon. Many methods are extensively studied and applied in fields to tackle this problem of condensate banking. Critical overview is hereby provided of these methods in this chapter showing their advantages and limitations and in which scenario they are best to use. Mainly these techniques are:

- **Productivity Improvement Methods:**

The idea is to decrease pressure drop in the vicinity of wellbore leading to delayed dew point, and hence we can produce single phase gas for a longer period of time. This type of methods includes drilling horizontal wells, techniques of matrix acidizing & hydraulic fracturing.

- **Pressure Maintenance Methods:**

The main aim is to maintain the pressure of reservoir above dew point, which means no condensation, will take place, and liquid dropout will not happen, and heavy ends will be easily produced to surface. These techniques include gas cycling for pressure maintenance, injection of CO2 and N2.

- **Chemical Injection Methods:**

These techniques include use of solvents, using chemicals to change the wettability preference of rocks. The aim is to mitigate condensate blockage. The mechanism of these methods is described in detail in this chapter.

Given below is the description of these different techniques along with their field application and also different case studies.

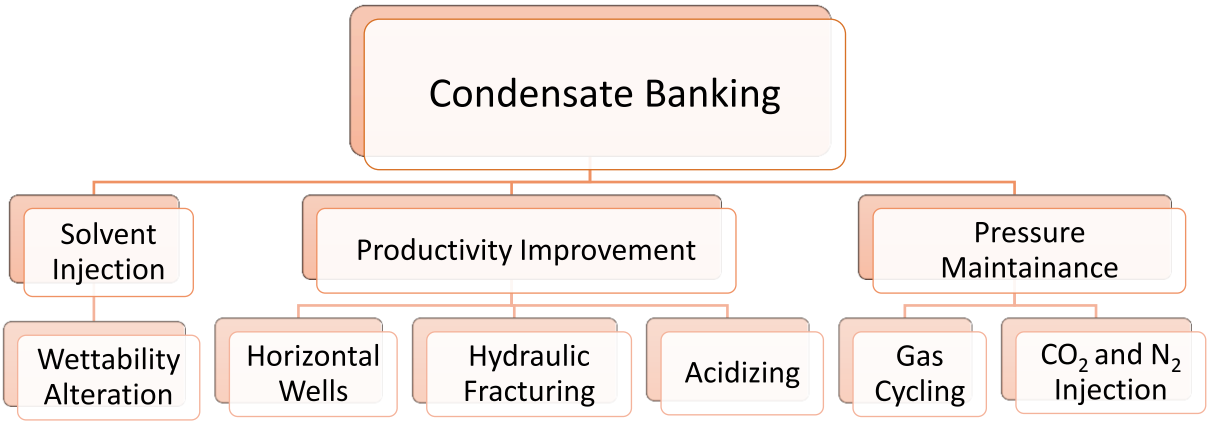

Figure 4-1 Condensate-banking mitigation strategies.

4.1 Productivity Improvement Methods:

4.1.1 Horizontal Wells:

Horizontal wells increase contact area of reservoir and well, which means lesser pressure drop around the wellbore. So even if operator produces horizontal well at higher rates i.e. there will be higher pressure drop, but this pressure drop will be distributed over the large contact area. Horizontal wells hence cause an increase of productivity by delaying dew point and decreasing the happening of condensate banking. It means that horizontal wells play a remedial job for the condensate blockage i.e. it can only delay dew point but once dew point is reached liquids will start accumulating nearby the wellbore. Furthermore, drilling horizontal well could prove quite expensive in some circumstances [35]. This is due to the fact that an average horizontal well is more expensive and difficult to drill compared to an average vertical well. The main goal of drilling horizontal well is to enhance oil production, so in circumstances where this improvement is less attractive compared to vertical well then a precise cost-benefit analysis needs to be done for horizontal drilling. However in many types of reservoirs the potential benefits of drilling horizontal wells are obvious. These include thin reservoirs, reservoirs with natural vertical fractures, thin layered reservoirs, heterogeneous reservoirs, reservoirs with a potential to develop water or gas coning etc. [94].

4.1.1.1 Case studies & Field applications:

Muladi et al. (1999) did a simulation study to compare the production efficiency of vertical well with horizontal well in the gas-condensate reservoirs with heterogeneities. A Cartesian 3D model was built using LGR to visualize the vicinity of wellbore in a better way. They concluded that production efficiency of horizontal well was better for reservoir whose average permeability is higher than 1 mD, conversely for reservoirs with average permeability≤1 mD preferable option is vertical well. This is because of the fact that in high average permeability reservoirs fluid has a high mobility and can move easily to horizontal well along vertical direction [36].

Dehane and co-researchers (2000) studied horizontal wells performance in comparison to vertical wells performance in gas-condensate reservoirs under different depletion schemes. They found that horizontal wells undergo less drawdown pressures than the vertical wells, and that there is lower accumulation of liquid nearby wellbore for horizontal wells. They also found that in case of horizontal wells increasing the drainhole length increases the productivity [37].

Marir et al. (2006) did a simulation study using data from horizontal-wells in Hassi R' Mel field (Algeria) to study water production and recovery of condensate. The results depicted that horizontal wells are useful as they increase the water breakthrough time and also improves the condensate recovery [38].

Miller (2010) using a simulation study inspected the influence of horizontal-wells to reduce condensate banking phenomena in a gas-condensate reservoir located in North field of Qatar. North-field is giant gas-condensate reservoir in offshore Qatar. For the simulation study two numerical well models were built, one model for horizontal well using Cartesian coordinates and other model for vertical well using radial coordinates. The results indicated that horizontal well features lower drawdown in comparison to vertical well, leading to lower water conning phenomena and lower condensate accumulation nearby the wellbore. Moreover PI for the horizontal wells was also higher. The reason for all this is that in horizontal wells we have higher contact area in-between reservoir and the well and that horizontal wells delay the formation of the condensate bank nearby the wellbore [39].

4.1.2 Hydraulic Fracturing:

The main idea behind hydraulic-fracturing is that it makes a longer conductive passage between well and reservoir, so that creating an ease for the fluid flow into the wellbore. So hydraulic fracturing and acid fracturing both are promising techniques to enhance gas-condensate reservoir wells performance. Like horizontal wells hydraulic fracturing also increases contact area in-between the well and the reservoir hence reducing pressure drop nearby the wellbore and ultimately delaying accumulation of liquid condensate nearby the wellbore. This means that hydraulic fracturing only delays the problem of condensate banking and don’t prevent it permanently. As the time passes and production increases it will cause the drawdown to increase and the condensate banking may start again. Conductivity of fractures is detrimental for improvement of well productivity, whereas conductivity of fracture is largely controlled by chemistry of fluid that is used for hydraulic fracturing. So right design of fracturing technique and right selection of hydraulic fracturing fluid helps to improve the post treatment well performance [40]. Similarly proppant particles are also vital in controlling hydraulic fracture conductivity and production rate. The idea is that once hydraulic fracture is created then during production the pore pressure decreases and the effective stress of the rock matrix increases, hich can lead to closing of the fracture. So proppant particles is the material used widely in oil gas industry to prevent the induced hydraulic fractures from closing. Proppant particles are materials normally sand, treated sand or man-made ceramic materials [95].

4.1.2.1 Case studies & Field applications:

Carlson et al. (1995) showed in their studies that doing hydraulic fracturing in gas condensate wells leads to reduction in drawdown pressure and hence less liquid dropout occurs [41].

Settari et al. (1996) inspected effect of hydraulic fracturing technique on PI of wells in the gas-condensate reservoirs located in a field in Norway. They noticed that increasing conductivity of fracture increases productivity of both the liquid and the gas phases. Also increasing length of fracture has positive effect on well productivity. Additionally, they observed, multi-phase flow below dew point is highly undesirable as it reduces the PI of an unfractured well by 50%. Fracturing the well can restore the PI of well to initial value before the multiphase flow and even to higher PI values than initial one [43].

Hashmi et al. (2000) did a compositional-simulation study to inspect effect of hydraulic fracturing technique on productivity of wells in gas-condensate reservoirs. In model they used a stratified formation comprising of 5 layers and with permeabilities ranging from a minimum of 0.08 mD to a maximum of 115 mD. It was observed that hydraulic fracturing delays dew point pressure, hence delays the happening of condensate banking. One problem associated with hydraulic-fracturing is that liquid accumulates perpendicular to fracture face causing damage of fracture-face and hence reducing the permeability [43].

Aly et al. (2001) did a simulation study on multi-layered rich gas-condensate reservoirs with low permeability with fracture modeling and compositional simulation. The results from the study showed that hydraulic fracturing increased the production rate and the production plateau was extended [44].

Ignatyev et al. (2011) studied influence of the hydraulic-fracturing in case of horizontal-wells in gas-condensate fields in Russia. The results displayed that fractured horizontal wells show productivity 9 folds greater than unfractuured horizontal wells whereas 3 folds greater than fractured vertical wells [45].

In a field case a gas-condensate reservoir in the Delta field was hit by production impairment due to condensate banking when the pressure of reservoir declined below dew point. The problem was economically tackled by hydraulic fracturing, whereas in one well production was increased 3 times after fracturing [46].

4.1.3 Acidizing:

Acid treatments are used for stimulation of wells. In carbonate formations acid treatment is done to dissolve part of reservoir rock to create fractures or wormholes [47]. While in case of sandstone formations usually formation damage results from drilling as well as completion fluids invasion, workover etc. Acid treatment is therefore done to remove this formation damage, hence to restore the original permeability of reservoir [48], [49].

Acidizing of matrix is a promising solution for reduction of condensate banking. A limitation to acidizing for some acid systems maybe the high temperatures usually encountered in gas-condensate reservoirs. For instance reaction of HCL and carbonates at 200 ^oF or higher temperatures is quite fast, and leads to higher consumption of acid and wormholes are not created.

4.1.3.1 Case Studies:

Al Anazi and co-researchers (2006) studied the stimulation of sandstone & carbonate gas reservoirs by treatment with alcoholic acids. They detected that some wells took around 1 year after the liquid injection to restore the initially gas productivity. Then methanol was added to acid solutions and core-flood tests were carried out on core samples of sandstone. They observed that alcoholic acids react slowly with reservoir rocks in comparison to regular acids. Also addition of methanol showed deeper penetration of acid and hence deeper stimulation [50].

In a case study by Trehan et al. (2012) two wells in low-permeability gas-condensate reservoir were affected by condensate banking problem and production rates were decreased to a level which was economically not viable. So to elevate productivity of wells, matrix of reservoir rock was perforated and then foamed matrix acidizing was done. The treatment was very successful and the production rates were increased [51].

4.2 Pressure Maintenance Methods:

4.2.1 Gas Cycling

To maintain pressure of reservoir so that the productivity and hence recovery of gas-condensate reservoir may increase, we are inclined to use gas injection, which may be natural-gas or we may employ the injection of Nitrogen (N_2). The concept behind the injection to enhance pressure is to keep pressure above the dew-point of the reservoir; hence in this we will be able to restrict formation of the condensate which is hindering recovery of our reservoir. Furthermore, this injection will also facilitate the re-vaporization of liquid that might have been formed back in gas phase. If we are successful in maintaining pressure of reservoir above dew-point then recovery of the condensate ought to be 100% [52]. To be certain whether gas injection will give us the optimum recovery for a specific gas-condensate reservoir there exist two parameters which are deciding factors in determining this step: flow characteristics of the reservoir i.e. Areal & vertical sweep efficiencies and phase-behavior of the fluid i.e. re-vaporization of the condensate. Up to75% of condensate recovery can be attained by recycling of dry dry-gas in reservoir [52]. Areal sweep efficiency for any displacement process is the areal portion of the reservoir which is contacted by the displacing fluid (Recycled gas in this case). Whereas vertical sweep efficiency indicates the one-dimensional vertical height of the pay zone that has been contacted by the displacing fluid.

4.2.1.1 Simulation Studies:

Geological and petro-physical parameters are one of very important consideration while thinking about the simulation studies as these considerations would immensely help in constructing the optimum models and help forecasting the scenario that would allow the maximum recovery of the condensate from gas-condensate reservoir through application of gas-cycling methods. Many simulation activities have been completed so far by a number of researchers. In Algeria the field of Toual (Belaifa et al.2003), Hassi RMel south (Adel et al. 2006), western-siberian field (Kolbikov 2010).

One case study conducted where the data is taken from the different producing fields of West Africa pointed out towards the increase liquid recovery in case of depletion, is dependent on reservoir permeability, the distance between producer and injector, and the voidage-replacement ratio [55]. Study also indicated that the increased and improved condensate recovery is in relation with large reservoirs and breakthrough of lean gas when delayed. They pointed out increase in recovery factor with increase in voidage-replacement ratio.

In another case study, gas-recycling in the Bodcaw reservoir in the Cotton Valley field, researchers Miller et al. in 1946 presented the following findings: At the initial conditions of reservoir at pressure of 400psig and temperature of 238^{o}F, production of the effluent was single gas phase and liquid hydrocarbon contents that were condensable 113.98 bbl/MMcf, dew-point and temperature figures were 3975 psi and 238^{o}F. They pointed out the financial feasibility of this field with recovery of 85% by production of 115% of these gas reservoirs [56]. Another project in Abu-Dhabi aimed the development of two gas-condensate reservoirs where a toil to demonstrate the basic design and to delineate the surface facilities (onshore) and project implementation were performed [57].

4.2.2 Use of Nitrogen (N_2):

Nitrogen gas was used instead of utilizing the dry gas which is produced from the reservoir due to economic constraints because previously produced gas is almost always pondered to inject in the gas-condensate reservoirs.

4.2.2.1 Simulation Studies:

In 1981 a comparison was tossed by Donohoe et al. where they compared injection of lean-gas and Nitrogen gas for three different type of imaginary fluids. Condensate recovery was reported in both cases for gas-condensate reservoir with injection of reservoir gas and with the injection of Nitrogen gas, while process of the production was taken as depletion drive. Three different level of heterogeneity of reservoirs was considered for this purpose to show the wide spectrum and clear picture of case concerned. They had concluded and showed that the recovery factors with injection of Nitrogen in all three cases were like the values of in case of lean gas injection. They summed that those reservoirs having streams higher than 100 bbl/MMcf of condensate ought to be considered where injection of Nitrogen is the strong contender [58]. Also, where the production rates and the injection rates are kept unchanging, the reservoirs with the lower level of heterogeneity could be thought for the use of Nitrogen injection as practicable and acceptable solution [52].

Core-flood experiments and simulation models were used to consider the ability of Nitrogen to displace gas condensate. The condition for the core-flood experiments used were pressure range between 4500 psi to 5700 and temperature of 215^{o}F with separator gas and Nitrogen. In quest to simulate laboratory experiments of core-flood, they used compositional model. They indicated that while using the separator gas as displacement agent there was small improvement as in comparison to Nitrogen. Further stating they said that below dew point when Nitrogen or separator gas used as displacing agents the displacement of condensate reduce the recoverable condensate. Therefore, it is suggested that in the early life of gas-condensate reservoir it is in good interest to inject gas as pressure maintenance strategy [59]. In another investigation researchers used the 1D compositional model to evaluate and to compare the action of Nitrogen and gas-cycling to see which would recover more condensate in gas-condensate reservoir [60]. It was stated that natural gas had achieved the less liquid dropout accompanied with superior ability in evaporation liquid condensate than that of Nitrogen.

In 2008 Linderman and co-researchers used compositional-model for full-field simulation to see the suitability of N_2 injection in large reservoir of gas-condensate. They reached on the opinion that if we use only Nitrogen gas as injection then the recovery is relatively less as in compared to when we use the combination of lean gas and Nitrogen and also the risk of banking is reduced when combination is used. When we compare injection of Nitrogen and of Carbon dioxide, Nitrogen achieve the elevated gas recovery but lower liquid condensate recovery. They pointed although Nitrogen has low effect on the condensate recovery but high effect on the whole hydrocarbon recovery i.e. gas recovery plus liquid. In related study researchers, to replace and avoid the reinjection of produced natural gas with associated hurdles in case of carbon dioxide, and the flue gases injection, Nitrogen was used. In two scenarios of Nitrogen injection: namely, all field and second one is isolated scenario. They proposed that isolated scenario was advantageous in consideration of specifications of final gas and this would also need less requirements of gas separation [61].

4.2.3 Carbon Dioxide Injection:

As per the fact the quantity of Carbon-dioxide is increasing day by day contributing in the greenhouse gases, scientists and researchers have started considering the injection of Carbon-dioxide underground in the depleted-gas reservoirs to capture it [62]. CO_2 is injected into the oil reservoirs so that recovery of oil can be maximized. The concept of injection of Carbon-dioxide is it lowers down dew point pressure of oil or gas system [63]. Carbon dioxide can also recover unrecoverable gas to certain extent as it helps in improving sweep efficiency then re-pressurization of gas fields. CO_2 injection could reduce the miscibility pressure for the paraffin, and help in recovery of liquid condensate in the depleted reservoirs that have condensate [64]. Local displacement efficiency, flow of fluid in reservoir are determinants of the efficiency of Carbon-dioxide injection.

In another linked study researchers investigated the relative permeability, fractional-condensate recovery by Carbon-dioxide injection, natural gas injection (methane) and for both mixture of Carbon-dioxide and methane [65]. In another experiment Sandstone with the permeability 22-92 mD and porosity 13.2-14.7% were used. They pointed that capacity of Carbon-dioxide which is supercritical in 62% as compared of pore volume. Injection of Carbon-dioxide not only did improve the permeability but also boosted recovery of condensates. Moradi and co-researcher discovered CO_2 injection would attain the maximum of gas and the liquid recovery [66].

In 2011 a study conducted by Gachuz-Muro to compare the effectiveness of injection of N_2, CO_2 and for dry lean gas which are employed in the fractured condensate reservoirs to displace condensates. The finding showed that Carbon-dioxide have the higher recovery than that of Nitrogen but has the lower recovery when comparison is performed to natural gas [67]. In the dipping gas-condensate reservoirs CO_2 has the higher recoveries as compared to mixture of Carbon-dioxide and methane [68]. In one numerical simulation by using compositional simulator Kurdi et al. 2012 explored the consequence of supercritical Carbon-dioxide injection on condensate bank removal. Findings presented were: decrease in viscosity of condensate, increase in density of gas, and reduction in density of condensate. It also dropped surface tension between surfaces consequently resulted in decrease in capillary pressure. In a numerical simulation study which use the miscible and the immiscible gas to remove the condensate banking in fractured-gas-condensate reservoirs. They found due to fracture there is higher saturation in matrix and hence higher recovery. Miscible-gas injection would give higher recovery in comparison to immiscible [69].

Carbon dioxide entails different problem at it source, transportation and storage. Main source of production is industries as these emit it in as byproduct often, these industries use different kind of fuels to burn. In the transportation phase supercritical CO_2 may cause the corrosion in the pipelines in which it is being transported. When contaminated with water it produced the Carbonic-acid which is corrosive in its nature. Although it is weak acid, but it can corrode mild steel.

4.2.3.1 Discussion

As above discussion it appears that gas recycling is ideal process which presents the promising answer to the serious problem of retrograde condensation. But still there are many factors involved. Firstly, in said scenario income from the of gas in reduced, at the start there is big requirement for the compression and injection equipment. At time we have to purchase the gas which adds the more financial pressure and it would be a long-term process. Therefore, before exploring the wet gas field all such factors needed to be taken care very seriously so that in future any setback can be handled effectively. In term of theory gas cycling can replace 100% of effluents and hence can prevent condensate banking. In the times, when charge of natural gas is low it is good to consider the reinjection of this gas. As of presently natural-gas is very critical and primary fuel with high demand. Therefore, injection of N_2 and CO_2 ought to be taken in care. Therefore, key deciding factors in determining the feasibility are defining the sources of the gas, its transportation its storage limitations along with injection capabilities holds paramount importance in decision making.

4.3 Chemical Injection Methods:

4.3.1 Use of Solvents:

In near wellbore zone relative-permeability of gas is reduced because of condensate blockage. Alcohols having low molecular-weight and solvents are used to improve relative-permeability of gas. It's a two prong approach by which these solvents increase relative-permeability of gas: First these solvents lessen the interfacial tension forces in between the gas phase and condensate, Secondly the solvents dissolve some part of condensate to the producing gas. Methanol is a perfect example for such cases. Du et al. (2000) discovered that methanol increased the end points of relative-permeability of gas by 1.2 to 2.5 times. This is because methanol has the ability to displace as well as dissolve accumulation of the water and condensate accumulation also [70].

Al-Anazi (2002) found that use of methanol as solvent delays the condensate accumulation because it creates a methanol-rich intermediate phase, and this phase dissolves gas and water [71]. Al-Anazi (2005a) found that methanol displaces both water and condensate banking by multicontact miscible technique [72]. Bang and co-researchers (2010a) found that use of methanol delays the condensate dropout because it lowers dew point when added to a water and condensate mixture. They also studied other solvents which are widely used for mitigation of gas-condensate blockage i.e. methanol, isopropyl-alcohol (IPA) and ethanol [73]. Given below are properties of these solvents:

Parameter	Methanol	IPA	Ethanol
Molecular formula	CH_3OH	$(CH_3)_2CHOH$	CH_3CH_2OH
Molar mass (g mol^{-1})	32.04	60.10	46.07
Density (g/cm^3)	0.7918	0.786	0.789
Boiling point (°F)	148	181	173
Flash point (°F)	54	55	54
Auto-ignition temperature (°F)	725	750.2	797

Figure 4-2 Properties of solvents commonly used for mitigation of problem condensate blockage [73].

4.3.1.1 Experimental Studies:

Extensive studies were conducted to investigate use of different solvents in gas-condensate reservoirs for mitigation of condensate-banking and to remove water. The different solvents investigated were IPA, methanol, mixture of methanol & water, mixture of IPA and methanol. The experiments were done on sandstone & carbonate formations with a variety of permeabilities. The following results were observed:

Al-Anazi and co-researchers (2002) investigated in his coreflood experiments by using synthetic mixture of gas-condensate the use of methanol for mitigating condensate & water bank. They achieved a condensate accumulation in the core which simulates the situation in near well region of a producing well. Due to accumulation relative permeability to gases was reduced by 95%. When water saturation was increased it consequently decreased relative permeabilities of both the gas and oil. They did methanol treatment with 2 stages and observed that after first stage both gas flow and PI was increased. But they observed that with time methanol is stripped by the gas and produced so condensate accumulation starts again. The experiment concluded that methanol increased relative-permeability of gas for 0 to 54% of water saturation [71].

Al-Anazi and co-researchers (2005c) investigated efficacy of methanol, IPA, mixture of methanol and mixture of IPA and methanol for treating condensate blockage. Mixture of methanol and water was not effective to remove condensate bank. Methanol and mixture of IPA and methanol were effective to remove water [74].

4.3.1.2 Field Cases:

Al-Anazi and co-researchers (2005b) described a field case of a field located in Alabama in which methanol treatment was done to mitigate condensate bank. Condensate and gas production rates were severely declined because of condensate blockage. After treatment with 1000 bbl of methanol the production rate of gas was increased from 0.25 MMscf/D to 0.5 MMscf/D and condensate production rate increased from 87 BOBD to 157 BOPD i.e. condensate blockage was effectively removed. For 4 months the production was increased two times, but after 4 months it started declining again [75].

4.3.1.3 Discussion:

Using solvents like methanol, IPA etc. to remove water & condensate banking in gas-condensate reservoirs are very effective in sandstone & carbonate formations. Moreover, solvent treatments are efficient in low & high permeability formations. The major limitation of this method is that it isn't permanent solution and after some time of production condensate accumulation problem hits back.

4.3.2 Wettability-Alteration Chemicals:

To increase productivity of gas wells that are being produced from condensate reservoir, it is helpful if we change the system from oil-gas wet to gas-wet system. The importance of wettability can be gauged from the fact that the onslaught of water-flooding is highly depended upon this rock wettability [93]. Following equation explains this phenomenon:

$$Pc = \frac{\gamma \cos(\theta)}{\left(\frac{k}{\phi}\right)^{1/2}}$$

P_c is capillary pressure

k is rock permeability

ϕ is rock porosity

γ is interfacial tension

θ is contact angle

Contact angle between surface and fluid is important factor that controls the wettability. Let say if we have two immiscible A&B fluids in porous-rock then we can find out the wettability with help of contact angle, that is measured in denser-phase.

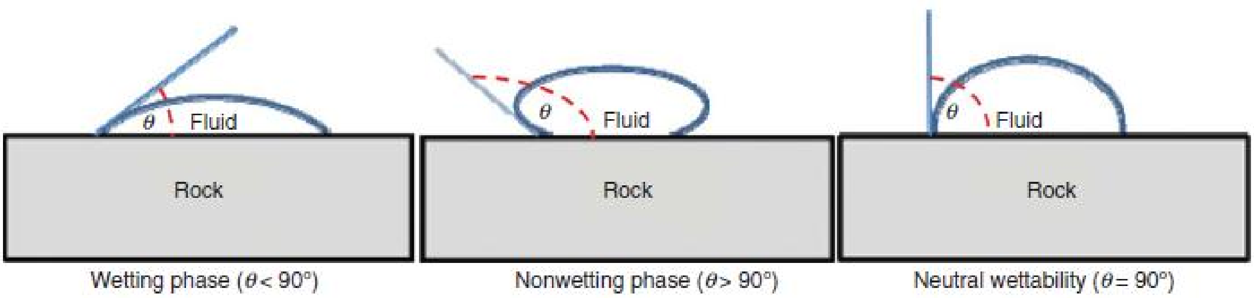

Figure 4-3 Representation of wettability with contact angle of fluid [35].

These are the static contact-angles, pendant-drop instrument is considered to measure contact angle dynamically. Both, advancing and returning measurements are recorded. The denser phase can be named wetting phase if angle in less than 90^o, and on flip-side if angle is higher from90^o then we call it non-wetting phase. In a condition where angle matches 90^o then we name it as neutral wetting phase [76].

In fluoropolymers, there are hydrophobic parts with surfactant with the back-chain consisting fluorine [77]. These chemicals have got some distinguished properties of chemical stability and ability to lower surface tension in water system. In fluorinated surfactants, in term of structure, there is hydrophilic, hydrophobic-oleo phobic tail containing higher amount of fluorine, also presence of hydrophilic-group and spacer containing organic-group linking [78].

However, some potential health hazards are reported associating with degraded products of fluoro-polymers, such as perfluorooctane-sulfonate and perfluorooctanoic-acid, these both are toxic [79]. In 2002 Weber signaled that these chemicals could accumulate in bodies of animals and humans owing their long-lasting presence in environment. In a study to investigate half-life of PFOS was conducted, which was 4.8 years to 7.8 years [80].

4.3.2.1 Reducing Condensate Banking using Fluorosufactants and Polymers by Changing Wettability

In recent two decades, using chemical has received tremendous attention in using in wettability alteration. Experimental works started in the range of room temperature then researcher extended this approach to even elevated temperature up-to 161^{o}C [81]. In these studies, various fluoropolymers were studied with the major focus on the contact angle, imbibition test were performed, core-flood analysis were performed in conditions of higher temperature and surmounting pressure. In these experiments carbonate cores and sandstone cores of both, outcrop and from within reservoir source, samples were obtained with medium and low permeability. With the help of chemicals used for alteration of wettability, normally, oil-wet or water-wet system is changed to intermediate wetting or gas wetting. Chemicals present effective solution for wettability-alteration in problem of condensate banking in gas reservoirs.

4.3.2.2 Experimental Studies

In Berea field sandstone, imbibition of n-Decane was lessened effectively by using chemicals and water-imbibition reduced to zero [82]. Relative-permeability for gas is increased and amount of residual-oil was reduced after treating core sample with chemicals [83], [84]. These chemicals can also lower down the velocity coefficient (Noh et al. 2006). For improving fracture conductivity, wettability-alteration chemicals help through changing wettability of rock [85].

In 2007 Fahes concluded that at 140^{o}C, wettability was stable and this helped in improving the gas productivity. When we increase concentration of chemical, quantity of water imbibition goes down without adversely affecting rock permeability. Panga in 2007 suggested if the chemicals are used with fluorochemicals it might cause the absorption of chemical on surface of core that ultimately lowers the injectivity and non-uniform distribution of chemical alongside the core length.

Noh in 2008 concluded that chemical adsorption on rock is in direct relation to the concentration of chemical used. More using of chemicals resulted in lowering the permeability of rock-core therefore, pre-treatment of rock-core is often recommended to remain on the safe side so that decrease in permeability might not occur. Treatment that used chemicals related to fluoropolymers, water-imbibition is reduced 90% and of condensate imbibition by 50% [86].

Bang and research-fellows in 2009 concurred that core treated with fluoropolymers showed reduction in pressure-drop suggesting the improvement in relative permeability to gas two-folds, and also this treatment proved quite efficient [87]. Researchers, conducted another study, pointed out, mixture of ethanol and 2-butoxyethnol and mixture of propylene-glycol and isopropyl-alcohol, proved optimal for Berea-sandstone. Firoozabadi in 2010 found that existence of brine i.e. salinity of water affects the performance and effectiveness of fluorochemicals [76]. Fahimpour in 2012 suggested that alcohol based solvents are more operative than brine based. Concentration of chemicals has to be adjusted to maximize efficiency [88].

Non-anionic and anionic-surfactants are useful in lowering interfacial tension for gas-water system and condensate-water system, but anionic surfactants proved more effective in this regard at higher temperature & pressure [89]. To change from strong oil wetting to weak oil wetting or water wetting anionic-surfactants were used.

Ahmed et al. in 2011 suggested that of brine is present, pretreatment entailing the preflushing the core with IPA before treatment with chemicals. In the experiments findings were: there is certain optimum concentration of fluorochemical, if we transgress and more of it, no discernable improvement can be seen [90].

4.3.2.3 Case Studies

In an experiment fluorochemicals were pumped and pushed with Nitrogen then soaking of 17 hours then flowing back in well. With this approach gas production increased 50% and oil production by 20%. After 25-days oil-rate returned to previous value that shows limited chemical distribution around wellbore [91]

In an investigation in Saudi-Arabia in 2003 a well was put on production with rate of 20MMcf/Day whereas in 2009 well encountered the unstable situations due accumulation of condensate around wellbore. Gas-rate plummeted to 1.56MMcf/Day and rate of condensate was 279B/Day with condensate/gas ratio 178bbl/MMcf. In the treatment preflush solvent then injecting 900bbl of main chemical treatment. Researchers pointed out that after producing three months, rate of condensate increased to 1152B/Day that is increase in the order of 313%, also gas-rate increased to 2.85MMcf/Day which is increase in the order of 83%. Furthermore, productivity didn't decrease even after two years. This shows stability of fluorochemical in reservoir formation [92].

4.3.2.4 Discussion

For the wettability alteration, use of fluorochemicals could provide very effective way out in condensate banking phenomenon. To lessen the problem of condensate banking, this method because of durability, flexibility to entail different reservoirs and minimum payout time holds vital importance. This method is also coupled with many other techniques such as hydraulic-fracturing and horizontal-wells for gaining greater benefits. However, more field studies are needed to understand the response and working of these chemicals. Factors such that, mineralogy, formation water, and selection of proper solvent, influence wettability alteration performance.

5. DISCUSSION & CONCLUSION

Producing gas-condensate reservoirs below dew point of the system, results in the formation of a condensate bank in vicinity of wellbore. This condensate bank is prime reason of productivity impairment and consequently reduction of gas & condensate recoveries. It is imperative to be aware from the very start of field production life that which production optimization strategy will be best if condensate-banking problem starts. Therefore, starting from the case studies available in literature a thorough overview is done in this thesis to identify and discuss the most crucial reservoir parameters, production parameters and mitigation strategies which affect the condensate-banking phenomena.

Producing gas-condensate reservoir below the dew point we have both oil and gas phases, relative permeability of the gas is a crucial parameter in controlling well deliverability. Since relative permeability of gas is severely reduced in the near wellbore region because of condensate banking, this causes loss of well deliverability. Gas condensate reservoirs with low absolute permeability are more vulnerable to condensate banking phenomena than high permeability reservoirs. The reason is that due to low permeability fluid suffer more pressure drop while flowing from far areas of reservoir to the wellbore, so further pressure drop in the near wellbore due to condensate blockage will severely affect the deliverability. Composition of the gas-condensate itself is very important for condensate banking phenomena. Rich gas-condensates having higher amount of condensable heavy ends will undergo more liquid dropout in the near wellbore below dew point than lean gas condensates. So rich gas condensates have higher tendency to form condensate bank. Wettability preference of the rock in the near wellbore affects the accumulation of liquid. Oil-wet rock will result in increased condensate saturation, whereas gas-wet rock decreases condensate accumulation in the near wellbore, increases relative permeabilities of both gas and oil and increases the productivity ultimately.

Different techniques could be applied either to delay the condensate-banking issue or to mitigate its effects if condensate-banking has already occurred in a gas-condensate reservoir. These techniques could be categorized into 3 categories i.e. Productivity improvement methods, Pressure maintenance methods and Chemical injection methods. A critical review was done of the experimental & simulation work, case studies and field cases from the technical literature regarding these techniques. Then objective was to understand advantages and limitations of different condensate banking mitigation techniques and to know under certain conditions which technique would be best to use. The summary of conclusions drawn is following:

- Drilling horizontal-wells increases the contact area between reservoir and well, hence will decrease the pressure-drop near wellbore, as well as hydraulic fracturing does and ultimately delays the condensate-banking issue. These techniques extend the production plateau in single phase below dew point, but accumulation of condensates will start once dew point is touched with time and with production. A limitation to horizontal well is that it can costly in some circumstances.
- Acid treatments could be done for stimulation of gas-condensate wells both in carbonate & sandstone formations. They mitigate the effect of condensate bank. The mechanism is that in carbonate-formations to create fractures & wormholes and in sandstone-formations to restore the original permeability after formation damage. Limitation of acidizing is that it is not feasible at high temperatures which is most likely the case in gas-condensate reservoirs as they are encountered at high depths.
- Gas injection cycling technique maintains the reservoir-pressure above dew point and so reduces the liquid dropout. It makes us able to do production in single gas-phase and increases gas & condensate recovery. But large gas-volumes are needed for injection, for an ideal gas-cycling process the volume of injected gas is higher than be produced gas from the reservoir. So this technique is preferable if the field is far from gas-processing facilities or when gas prices are very low. Today natural gas has turn out to be a major energy-source for world energy demand, making gas cycling a less preferable option for mitigation of condensate banking.
- Due to vital importance of natural gas nowadays for use in industries, power generation and other energy uses it isn't feasible to use gas cycling technique. Nitrogen and CO_2 could be therefore considered as a substitute for the future injection techniques for pressure maintenance. Especially CO_2 owing to its increased concentrations in atmosphere and worse environmental greenhouse affects, it is a good potential candidate to be used for the pressure maintenance.
- Solvents such as methanol & iso-propyl alcohol were found effective in removing condensate-banking in laboratory experiments on cores, as they enhance the relative permeability to gas which was reduced due to condensate-banking. But when applied in field they give short term improvement i.e. after some time accumulation starts again and we have to repeat the treatment. So disadvantage is its temporary nature. However advantages are these solvents might be used in low & high permeability formations, and might be used in carbonate & sandstone formations.

- Wettability-alteration of the rock in near-wellbore zone can be done for mitigation of condensate banking, as changing the rock from oil-wet to gas-wet improves the relative permeabilities to gas & oil and ultimately improves the productivity. It is an emerging technique since its successful application on field level started in recent years, so there is much room for research and improvement in this technique. However this is a very robust solution and its advantages include less cost, durability and design flexibility to be applied under various reservoir conditions.

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